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Techno-economic study on biomass-based small-scale combined heat and power production by gasification

Thesis submitted in partial fulfilment of the requirements for the degree of Master of Science in Technology.

Espoo 6.2.2017
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Abstract

Tämän diplomityön tavoitteena on arvioida VTT Gasgen pienen kokoluokan (0.1...8 MW_e) myötävirtakaasuttimen ja polttomoottorin yhdistetyn sähkön ja lämmöntuotannon (CHP) markkinapotentiaalia ja kilpailukykyä käytännön toimintaympäristössä. Gasgen-teknologia mahdollistaa tervojen hajotuksen myötävirtakaasuttimessa. Skaalattavuus ja laaja polttoainevalikoima erottavat teknologian muista myötävirtakaasuttimista. Kaasuttimen polttoaineeksi käyvät paikalliset puulajit, metsäteollisuuden sivutuotteet ja ligniinipitoiset maatalouden tähteet.

Kaasuttimen kannattavuutta arvioidaan kolmessa tapauksessa: 1. kaukolämmön yhteistuotanto, 2. puutuoteteollisuuden sähkön ja höyryn tuotanto ja 3. polttoöljyn tai maakaasun korvaaminen pienessä höyrykeskuksessa. Excel-pohjaisen massa- ja energiataseohjelman avulla lasketaan nettonykyarvo, vuosittainen kassavirta, vuosittainen tuotto, pääoman annuiteetti, takaisinmaksuaika, energian hintojen kannattavuusraja ja LCOE (levelized cost of energy). Herkkyystarkastelussa tutkitaan polttoaineen, sähkön, lämmön ja höyryn hintojen, sekä laitoskoon vaikutusta tuloksiin.

Kaukolämmön yhteistuotanto ei ole kannattavaa Suomen alhaisten sähkönhintojen myötä. 1 MW:n kaukolämpölaitoksen sähkön hinnan kannattavuusraja on 43 €/MWh. Kaukolämmön yhteistuotanto on kannattavaa esimerkiksi Japanin, Itävallan ja Iso-Britannian kannustimien avulla. Puutuoteteollisuudelle 8 MW höyryä tuottava laitos on kannattava saavuttaen alle 4 vuoden takaisinmaksuajan ja 29.8 % sisäisen koron. 750 kW höyrykeskuksessa polttoöljyn tai kaasun korvaaminen kaasuttimella on kannattavaa, jos laitos on käyttöikänsä lopussa.

Avainsanat biomassan kaasutus, pieni kokoluokka, CHP, teknis-taloudellinen laskenta, bioenergia

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Abstract

This thesis aims to evaluate the market potential and competitiveness of the VTT Gasgen downdraft gasifier coupled with internal combustion engine to produce small-scale (0.1…8 MW_e) CHP in a concrete operating environment. Gasgen technology integrates in-situ tar decomposition with fixed bed gasifier. The scalability and wide feedstock range differentiates the Gasgen technology from the other downdraft designs. Local wood species, forest industry by-products and high-lignin agricultural residues constitute the potential feedstocks of the gasifier.

The feasibility of the gasifier is evaluated in three cases: 1. district heating CHP plant, 2. industrial electricity and steam production in wood industry and 3. small steam plant replacing a fuel oil plant. The economics indicators calculated with the help of energy and mass balance sheets in Excel include NPV, annual cash flow, annual profit, annuity of capital, payback period, break-even prices and LCOE. The sensitivity of the results is evaluated by changing feedstock, electricity, heat and steam prices as well as comparing several plant sizes.

Case 1 remains unprofitable due to the low electricity prices in Finland. The break-even electricity price for a 1 MW district heating plant equals 43 €/MWh. The district heating CHP application is profitable with the subsidies provided by for instance Japan, Austria and UK. Case 2 industrial CHP producing 8 MW steam is highly profitable reaching a payback period of under 4 years and IRR of 29.8 %. At present oil and gas prices, the 750 kW steam plant (Case 3) is feasible if the existing fuel oil plant is at the end of its lifetime.

Keywords biomass gasification, small-scale, CHP, economic evaluation, bioenergy

Preface

This thesis is conducted as a part of the Biomass CHP technology development for global markets project (Gasgen) at VTT Technical Research Centre of Finland Ltd funded by Tekes – the Finnish Funding Agency for Innovation. The project is partly funded by European Regional Development Fund. The project aims to develop a small-scale (100…2000 kW_e) gasifier working more efficiently than boilers with a broad feedstock selection. The gasifier could start a new market segment for small-scale gasification.

First, I would like to thank my thesis advisor Ilkka Hiltunen and Esa Kurkela for giving me the opportunity to write my thesis as a part of this project. Thanks to my advisor Ilkka Hiltunen for the patience and flexibility while reading the different versions of this thesis and answering the little practical questions. Special thanks to Esa Kurkela for providing the support with the energy and mass balance sheet, as well as the encouraging words and good questions about the results.

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Finally, I thank my boyfriend, family and friends for the shared journey.

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Symbols

c		capital recovery factor
c_{p-avg}	[kJkg^{-1}°C^{-1}]	specific heat capacity of the gas
$c_{p-avg,i}$	[kJkg^{-1}°C^{-1}]	specific heat capacity of the gas component
e	[€/MWh]	electricity price
f	[€/MWh]	feedstock price
h	[h]	full load hours
$\dot{h}_{pg}$	[MW]	enthalpy of the product gas entering the engine
$\dot{h}_{air}$	[MW]	enthalpy flow of the combustion air
$\dot{h}_{fg}$	[MW]	flue gas losses
i		interest rate
I_0	[€]	initial investment
I	[€]	investment cost
$\dot{m}$	[kg/s]	mass flow
$m_{H_2O,condensed}$	[kg]	mass of condensed water
M_{H_2O}	[kg/mol]	molar mass of water
M_i	[kg/kmol]	molar mass of the component
w		mass percentage of the component
n	[a]	investment lifetime
$\dot{n}$	[mol/s]	molar flow of the gas component
O_f		fixed operation and maintenance costs
O_v	[€/MWh]	variable costs without feedstock cost
P_{el}	[kW$_e$,MW$_e$]	nominal power of the engine
p_{steam}	[Pa]	steam partial pressure
p_0	[Pa]	atmospheric pressure
Q_{input}	[MW]	feedstock energy content
Q_{losses}	[MW]	boiler losses
s	[€/MWh]	steam or heat price
T	[°C]	temperature
T_0	[°C]	reference temperature for the enthalpy, 25 °C
y		scaling factor
$\dot{V}$	[m^3/s]	volume flow
$V_{H_2O,1}$	[m^3]	volume of steam in the flue gas before the scrubber
$V_{H_2O,2}$	[m^3]	volume of steam in the flue gas after the scrubber
V_m	[m^3]	the molar volume of ideal gas
ϕ_{after}		vol-% of the component in the gas after the scrubber
ϕ_{before}		vol-% of the component in the gas before the scrubber
$\phi_{H_2O,1}$		vol-% of water in the gas before the scrubber
$\phi_{H_2O,2}$		vol-% of water in the gas after the scrubber
x		moisture content
$\Delta\dot{h}$	[MW]	enthalpy flow change
ΔH_{vap}	[MJ/kg]	vaporization heat of water
η_{boiler}		boiler efficiency
η_{drying}		dryer efficiency
$\eta_{el,bg}$		engine electrical efficiency with biogas

$\eta_{el,ng}$		engine electrical efficiency with natural gas
$\eta_{el,pg}$		engine electrical efficiency with product gas
$\eta_{scrubber}$		heat recovery efficiency of the scrubber
η_{steam}		steam generation efficiency
Φ	[MW]	district heating or steam power
Φ_{CO}	[MW]	CO loss
Φ_{drying}	[MW]	heat required for drying
$\Phi_{drying,ava}$	[MW]	available heat for drying
Φ_{engine}	[MW]	engine gross heat output
Φ_{f1}	[MW]	fuel power before drying
Φ_{f2}	[MW]	fuel power after drying
Φ_{fgb}	[MW]	heat output of the flue gas boiler
Φ_{pg}	[MW]	product gas chemical energy
Φ_{pgb}	[MW]	heat output of the product gas boiler
$\Phi_{cooling}$	[MW]	heat in the engine cooling water

Abbreviations

AC	annual costs
AP	annual profit
AR	annual revenues
BFB	bubbling fluidised bed
CHP	combined heat and power
CEPCI	chemical engineering plant cost index
CI	compression ignition
db	dry basis
DFB	dual fluidised bed
DH	district heating
EAC	equivalent annual cost
EU	European Union
ETS	Emission Trading System
FC	fuel cell
GBP	Great Britain Pound
GHG	greenhouse gas
GT	gas turbine
HRSG	heat recovery steam generator
ICE	internal combustion engine
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
IRR	internal rate of return
JPY	Japanese Yen
kW_e, MW_e	kilo/megawatt of electricity
LCOE	levelized cost of energy
LHV	lower heating value
LVL	laminated veneer lumber
m-%	mass percentage
MC	moisture content
MCFC	molten carbonate fuel cell
mGT	micro gas turbine
NO_x	nitrogen oxides
NPV	net present value
NREAP	National Renewable Energy Action Plan
OECD	Organisation for Economic Co-operation and Development
OM	operation and maintenance
ORC	organic Rankine cycle
PBP	payback period
ppm	parts per million
RES	renewable energy supply
SE	steam engine
SI	spark ignition
SOFC	solid oxide fuel cell
ST	steam turbine
UK	the United Kingdom
USD	United States Dollar
vol-%	volumetric percentage
wb	wet basis

Introduction

1.1 Background

Renewable energy sources are promoted increasingly due to climate change. Bioenergy represented one tenth of the world primary energy supply in 2013. Over 70 % of the renewable energy supply was met by biofuels and waste (Figure 1). The majority of the biofuels consists of solid biofuels and charcoal, which are consumed in Asian and African households. Biofuels and waste produce only 1.7 percent of the electricity. (IEA Statistics, 2015) Biomass reduces CO_2 emissions simultaneously balancing intermittent energy sources. Bioenergy could be applied in developing countries and in decentralized power production in farms, villages and small industry fuelled with local agricultural and industrial residues.

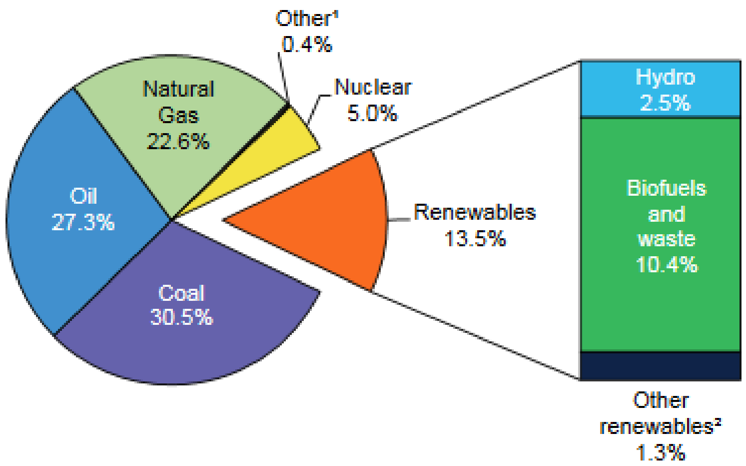


Figure 1. World primary energy supply fuels shares in 2013. (IEA Statistics, 2015)

Combined heat and power (CHP) production achieves high overall efficiency. In Europe, CHP is promoted and already employed in the forest industry, such as sawmills and plywood mills. Biomass could replace oil or natural gas in industrial applications. Electricity and cooling could be produced simultaneously from biomass in Japan and Brazil. Another application could be CHP in buildings (Streimikiene and Baležentis, 2013).

Biomass gasification is widely applied on micro scale, although gasifiers are not mass-produced at present. The efficiency of gasification exceeds that of combustion. Dong et al. emphasized the urgency for research demonstrating a commercial energy-efficient and low-cost small-scale biomass CHP. Commercially available small-scale biomass gasification CHP systems are scarce. (Dong, Liu and Riffat, 2009)

1.2 Research objectives

This thesis aims to evaluate the market potential and competitiveness of the VTT Gasgen downdraft gasifier coupled with internal combustion engine (ICE) to produce small-scale CHP in a concrete operating environment. The gasifier is compared to other small-scale gasifiers and the ICE is compared to other small-scale power production technologies in the literature study.

This thesis focuses on the techno-economic evaluation of the gasifier and an internal combustion engine CHP plant. Additionally, steam and heat-only plants are considered in the techno-economic analysis. The feasibility of the gasifier is evaluated in three cases:

1. district heating CHP plant
2. industrial electricity and steam production
3. small steam plant.

The feasibility study aims to choose the best environment to demonstrate the Gasgen technology. The effects of drying and product gas cleaning are taken into account. The feasibility is evaluated by calculating economic indicators including annual profit, net present value and payback period. Additionally, a sensitivity analysis of these indicators is conducted by varying feedstock and energy prices. Internal rate of return, break-even prices and levelized cost of energy are examined to further analyse the results.

The research questions are the following. At which electricity, heat and fuel prices is the technology feasible? What kind of subsidies would make it feasible, if it is not feasible without subsidies? Can biomass gasifier replace a heat-only boiler in district heating CHP application? Is it feasible to replace fuel oil or natural gas with biomass gasification at a steam plant?

1.3 Scope

This thesis is limited to small-scale biomass CHP technologies. The power output of the plant is limited to 100…8000 kW_e. This thesis focuses on gasification and internal combustion engines, which is the technology closest to market penetration (Bocci et al., 2014). The main competing technologies involve gasification with gas micro turbines and boilers paired with organic Rankine cycle and Stirling engines, as seen in Figure 2 (Vakalis and Baratieri, 2015).

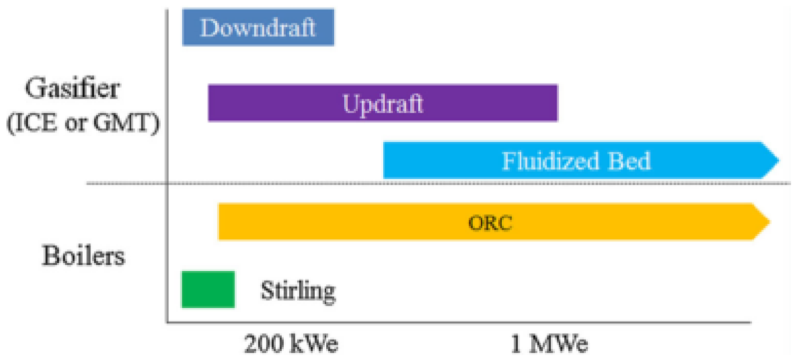


Figure 2. Range of applicability for biomass CHP technologies. (Vakalis and Baratieri, 2015)

Small-scale gasification technologies are commonly autothermal and the gasification is driven by char-gas reactions. (Vakalis and Baratieri, 2015) According to Basu, small-scale biomass gasifier types are fixed bed and fluid bed gasifiers (Basu, 2013b). Only these technologies are discussed in chapter 2.2, which describes the small-scale gasification technologies for biomass.

The selection of small-scale power generation technologies for comparison is limited to the commercial and near-commercial technologies. According to Gonzáles et al. small-scale CHP production options for woodchips gasification are ICE, gas turbine and Stirling engine. Combustion can be combined with steam turbine, steam engine, organic Rankine cycle (ORC) or Stirling engine. (González *et al.*, 2015) According to Salomón et al. fuel cells can also be considered commercial technology (Salomón *et al.*, 2011).

This thesis excludes several new technologies under development, including air bottoming cycle, evaporative gas turbine, externally fired gas turbine, pulverized wood-fired gas turbine or combustion engine, thermoionic converters and thermophotovoltaics. (Salomón *et al.*, 2011) The review on primary conversion technologies in chapter 2.1.1 is limited to combustion, gasification and pyrolysis of biomass. Landfill gas is discussed briefly, as it serves as a fuel in one of the case studies. The chapter excludes other biofuel conversions. The focus is on gasification. Pyrolysis, combustion and landfill gas are discussed briefly.

The scope of chapter 2.4, market perspectives, is global. However, cold climate and the resulting heat demand enhance the utilization of CHP. Secondly, domestic biomass feedstock supply, such as forest and agricultural residues or energy crops, promotes biomass CHP production. Thirdly, as biomass gasification remains in its demonstration and deployment phase, high education and awareness of new technologies contributes to the spreading of biomass gasification CHP. Thus, Finland, Germany, Austria, United Kingdom and Japan are inspected in more detail. The countries belong to the dominant countries in biomass gasification (Kirkels and Verbong, 2011) and existing gasifiers in smaller scale are situated there (Yagi and Nakata, 2011; Molino, Chianese and Musmarra, 2016).

This thesis embodies a literature study, techno-economic analysis and results. The literature study in chapter 2 comprises of small-scale power production technologies, gasification technologies, biomass as gasification CHP feedstock and markets perspectives for small-scale biomass gasification CHP. Chapter 3 describes the methods of the techno-economic study. Moreover, the chapter presents the cases and the techno-economic calculations. Chapter 4 describes the results of the economic evaluation of three cases: a district heating CHP plant, steam and electricity production for industry applications and the replacement of fuel oil or natural gas in a steam plant. Additionally, chapter 4.4 discusses the validity and reliability of the calculations.

2 Literature review

2.1 Small-scale biomass combined heat and power technologies

2.1.1 Primary and secondary technologies for biomass energy conversion

In order to produce both heat and power, energy in the biomass is converted to hot water, steam, gaseous or liquid products. The conversion technologies are called primary technologies. The thermal conversion processes include combustion, gasification, and pyrolysis. Chemical processes produce biofuels, which can be utilized in heat and power generation. (Dong, Liu and Riffat, 2009) This chapter reviews the thermal conversion processes. Additionally, landfill gas is discussed briefly.

Combustion is a complete oxidation process. In biomass combustion, the biomass is burned with air, generally in a stoker grate boiler in small-scale applications. The reaction products of hydrocarbons are composed mainly of carbon dioxide and water. Combustion releases heat at the temperature level of 80…1000°C. (González *et al.*, 2015)

Gasification is a partial oxidation process, which packs energy into chemical bonds in the product gas. Figure 3 pictures the process. Biomass and an oxidizing agent or medium react in an under-stoichiometric conditions and a variety of chemical compounds are formed. Gasification requires temperatures between 800 and 1000 °C. The main gasifying agents are oxygen, steam and air. In small-scale applications, the gasifying agent is usually air, as it costs less than oxygen or steam. (Basu, 2013b) Gasification products include char, product gas, tar, dust, ash and soot. The product gas contains mostly CO, CO_2, N_2, CH_4 and H_2. (Vakalis and Baratieri, 2015)

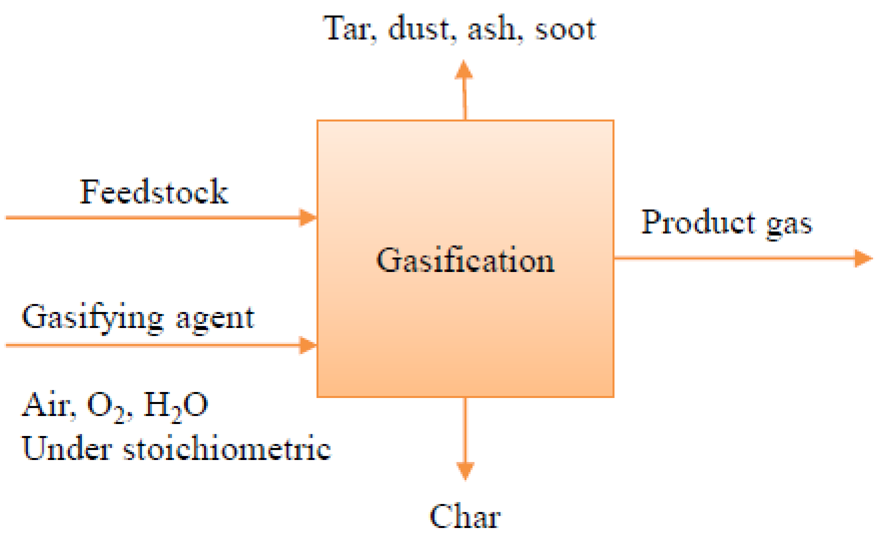


Figure 3. Gasification process and streams.

Four steps describe the biomass gasification process. Firstly, the biomass dries and excess moisture evaporates. Secondly, biomass decomposes thermally in devolatilization. Thirdly, the decomposed gases, vapours and some of the char are partially combusted. Fourthly, the decomposed products are gasified. (Basu, 2013b) Biomass gasification reactors can be autothermal or allothermal. Autothermal reactors provide the heat for char gasification reactions by oxidising part of the feedstock. The exhaust gases dilute the product gas. Allothermal (or indirect) gasifiers are heated externally to avoid the dilution of product gas. Small-scale gasification systems are usually autothermal. (Vakalis and Baratieri, 2015)

Pyrolysis is a thermochemical decomposition process in the absence of oxidizing agents. During pyrolysis, biomass breaks into smaller molecules of gas, liquid and char. Pyrolysis typically requires 300…650 °C temperatures. The primary liquid product called pyrolysis oil contains tars, heavier hydrocarbons and water. The solid char contains mostly carbon and the gas contains similar and heavier gaseous hydrocarbons as the product gas of gasification. (Basu, 2013b)

Landfill gas originates from the degradation of organic matter. Microbes generate methane in anaerobic conditions. Majority of the landfill gas is generated during10…20 years. Landfill gas composition varies in phases. The first phases of gas generation include aerobic, acid and methanogenic phases. Air intrusion, methane oxidation, carbon dioxide and soil air phases follow after the methane generation decelerates. The average landfill gas contains 50-60 % CH_4 and 40-50 % CO_2 during the methanogenic phase (Christensen, Manfredi and Knox, 2010)

Secondary technologies convert the product of the primary technologies into power. Internal combustion engines, gas turbines, steam turbines, organic Rankine cycle, fuel cells, steam engines and Stirling engine are discussed and compared in the following subchapters.

2.1.2 Internal Combustion Engine

Internal combustion engines (ICE) are a mature technology. ICEs are the common option for small-scale cogeneration. Internal combustion engines involve spark ignition (SI) or Otto engines, and compression ignition (CI) or Diesel engines. Natural gas fired Otto engines are competitive especially in the small-scale CHP plants below 2 MW_e (Salomón *et al.*, 2011). An internal combustion engine consists of a piston and cylinder, which convert pressure in the cylinder into rotational work. The engine process involves filling the cylinder with fuel and air, compression, combustion, expansion, and emptying the cylinder of combustion gases. (Brandin *et al.*, 2011, p. 54)

The spark ignition engine operates in four strokes (Figure 4). First, fuel-air mixture is fed into the chamber. Second, the piston compresses the mixture and a spark plug ignites it. Third, the flame spreads to the combustion chamber and moves the piston. Fourth, the flue gases are led out of the chamber. They contain emissions, which are mainly NO_x, CO and unburnt hydrocarbons. (Beith 2011, p.130-132)

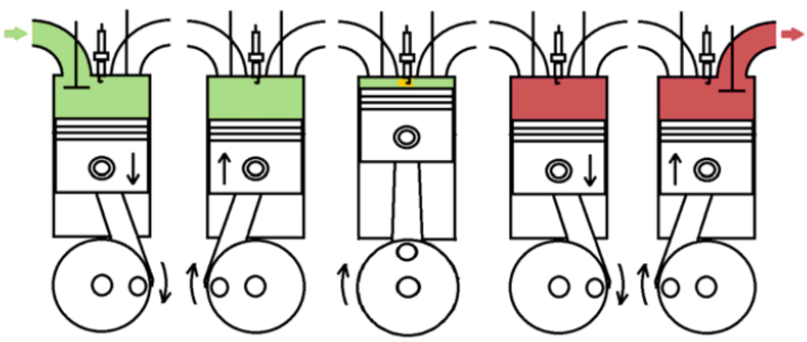


Figure 4. Four stroke engine operation: induction, compression, combustion and expansion, and exhaust stroke. (Brandin et al., 2011, p. 55)

The disadvantage of the SI engine is the knocking phenomenon, where the fuel-air mixture ignites spontaneously due to high pressure. It causes high mechanical stress to the piston rings and engine faces. Knocking is avoided by limiting the compression ratio below 10. (Mikalsen, 2011, pp. 130–132) Fortunately, the knocking point is above the maximum thermal efficiency compression ratio for product gas. Thus, no knocking occurs in SI engines optimized for product gas. (Vakalis and Baratieri, 2015)

In a compression ignition engine, the fuel is injected after compression and it self-ignites. The CI engines avoid knocking problems, since the combustion chamber contains no fuel in the compression phase. Thus, CI reach higher compression ratios than SI. The fuel choices are more limited for the CI than the SI engine, as the fuel has to self-ignite and have a suitable viscosity for fuel injection and spraying. The common fuels include diesel, fuel oils, biodiesel and vegetable oils. (Mikalsen, 2011, pp. 132–133)

Reciprocating internal combustion engines are well proven and reliable. However, they require frequent maintenance. They run on a variety of fuels including natural gas, hydrogen, biogas, product gas and alcohol fuels. The disadvantages of ICE are noise, vibration and exhaust gas emissions. (Mikalsen, 2011, pp. 125–130) ICE has high part load efficiency and electrical efficiency. Table 1 on page 21 compares numerically the different characteristics, such as efficiencies, of ICE and other power generation.

Engine electrical efficiency varies with size and fuel. Natural gas engines obtain higher efficiencies than biogas engines, which reach 36 percent. (Vukašinović *et al.*, 2016) Wood gas engine efficiency varies between 34.3 and 39.4 % in 650 to 1000 kW_e engines. Internal combustion engines achieve high part load efficiencies even with product gas as a fuel, as seen in Figure 5. (Herdin, 2014) Supercharging increases the electrical efficiency compared to naturally aspirated engines. More work is produced, since more air and fuel is injected to the cylinder. Turbocharging also exploits the energy in the exhaust gases. (Brandin *et al.*, 2011, p. 55)

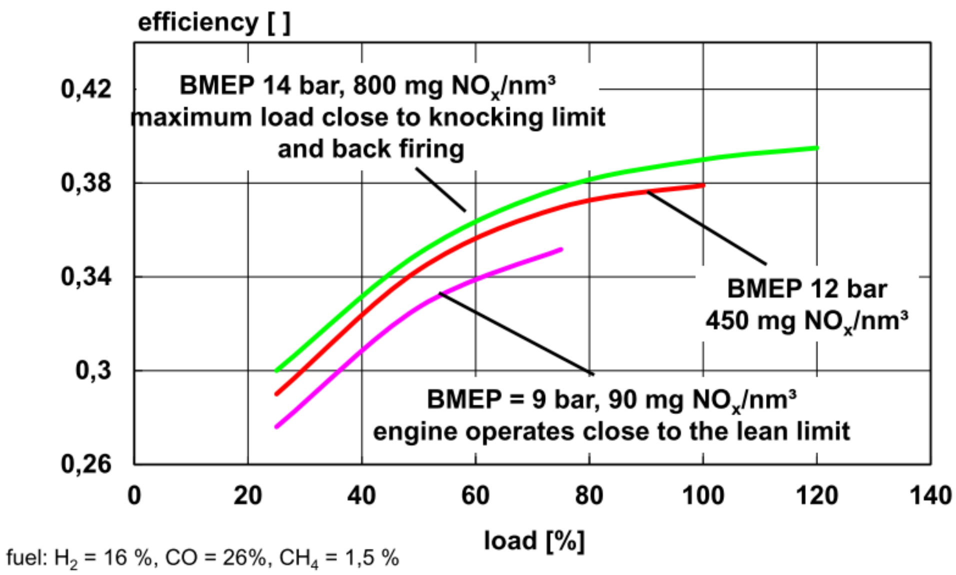


Figure 5. Wood gas engine part-load efficiency. (Herdin, 2014)

Both CI and SI engines can utilize product gas as a fuel with some design modifications. (Martínez *et al.*, 2012) The efficiency differs only slightly between natural gas and product gas, as not only the heating value of the fuel contributes to the combustion, but the energy in the air-fuel mixture as a whole influences the efficiency (Vakalis and Baratieri, 2015). Product gas is an efficient fuel for lean engine operation, as the energy content of the air-fuel mixture exceeds that of natural gas with air factors over 2.4 (Brandin *et al.*, 2011, pp. 80–81).

The emissions of the two engine types vary. The CI operates in lean conditions i.e. with excess air, and emits no CO or unburned hydrocarbons, as in SI engines. On the other hand, the NO_x and particulates emissions (soot) are significant. Catalysts can reduce NO_x emissions, but the costs are excessive for small-scale CHP production. The particulates can be filtered. (Mikalsen, 2011, p. 132-) For instance, EU (European Union) and United States Environmental Protection Agency standards regulate emissions. (Brandin *et al.*, 2011, pp. 62–65) Mostly, the emission limits are same for combustion and gasification. There are specific limits for gasification plants in Denmark and Germany. (Christiansen *et al.*, 2009)

2.1.3 Gas turbine

A gas turbine consists of a compressor, combustion chamber, turbine and generator (Figure 6). Air enters the compressor and is compressed to a higher pressure. Simultaneously, the air temperature rises. Compressed air continues to the combustion chamber. Fuel is injected into the chamber and the mixture burns. The flue gases rotate the turbine, which is connected to the compressor by a shaft. (Poullikkas, 2005) The shaft may also be attached to the generator. In this case, the turbine is called single shaft turbine. If the generator has a second shaft, it is called split shaft or two shaft gas turbine. (Ismail, Moghavvemi and Mahlia, 2013)

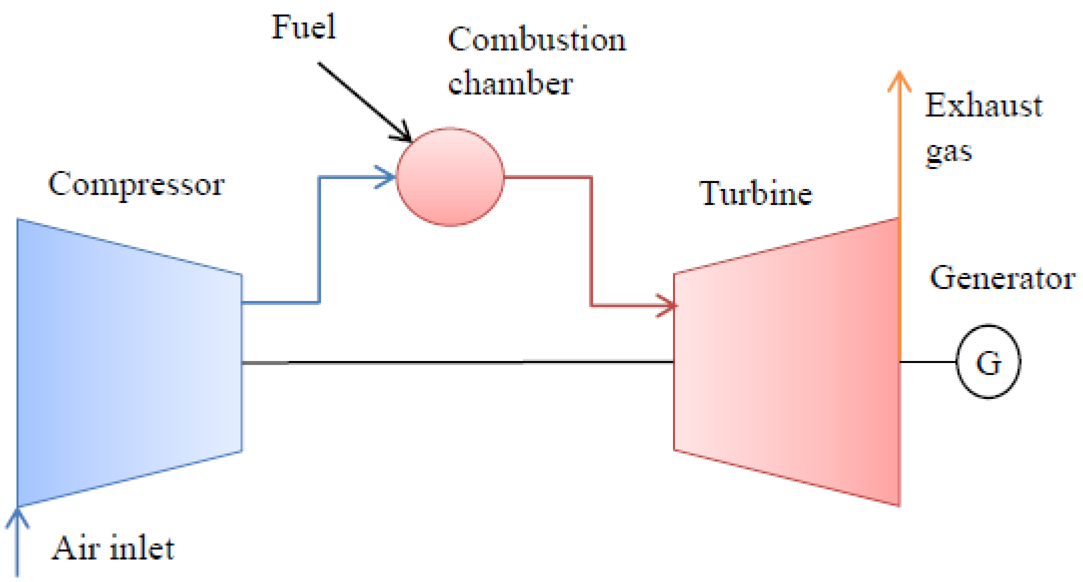


Figure 6. Gas turbine schematic.

The electrical efficiencies of modern gas turbines under 2 MW_e range from 16.5 to 25.5 percent with natural gas as a fuel. (Poullikkas, 2005) Microturbines fired with product gas are unavailable at the markets (Bang-Møller *et al.*, 2013). The efficiency of small gas turbines can be improved by adding a recuperator to the system. For microturbines (under 500 kW_e), the recuperator must be part of the installation in order to reach decent efficiencies. Recuperator recovers the heat from exhaust gas to heat the combustion air. (Soares, 2015)

The following factors affect gas turbine performance. Gas turbine efficiency increases with increased air density and vice versa. High inlet air temperature decreases the air density and therefore the efficiency declines. Similarly, the higher the altitude, the lower the air density and efficiency. (Poullikkas, 2005)

The advantages of gas turbines are low maintenance costs, long lifetime and suitability for CHP production due to the exhaust gas heat. (Arena, Di Gregorio and Santonastasi, 2010) The disadvantages include, poor part-load operation efficiency, moderately high investment costs and performance degradation as a result of compressor fouling. (Poullikkas, 2005)

Gas turbines can be connected to other small-scale power production devices. A gas turbine coupled with a steam turbine is called the combined cycle, which is mainly applied in large-scale plants between 10 and 850 MW_e. In small-scale power generation, installing a less complex power plant is cost-effective, due to the adverse effect of the economics of scale. Gas turbines can also be coupled with Diesel engines, Stirling engines and fuel cells. The Brayton-fuel cell cycle attracts attention, since the efficiency of the cycle is high. (Poullikkas, 2005) Recent research has concentrated on the integration of microturbines with other technologies. (Ismail, Moghavvemi and Mahlia, 2013)

2.1.4 Rankine cycle

Conventional Rankine cycle with a steam turbine is a mature technology in large-scale power plants. In biomass applications, they are coupled with bubbling fluidized bed boilers. Flue gas condensation increases the efficiency of the Rankine cycle.

Typical capacity minimum for a steam turbine is 0.5 MW_e (Ismail, Moghavvemi and Mahlia, 2013). Wärtsilä offers a BioGrate with a steam turbine in the 1…5 MW_e scale (Salomón *et al.*, 2011). The steam turbine might be feasible in small-scale applications in industrial setting, compared to a configuration with ORC (Pantaleo *et al.*, 2015).

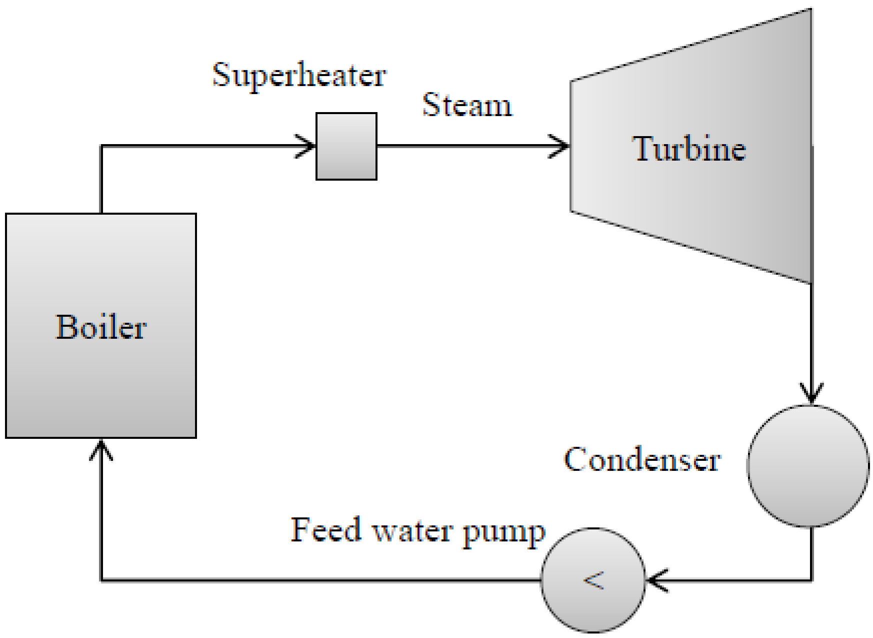


Figure 7. Rankine cycle schematic.

Figure 7 depicts the Rankine cycle. Firstly, combustion in a boiler vaporizes water. Secondly, the steam is superheated in the hottest regions of the boiler and then led to the steam turbine. Thirdly, the steam expands in the turbine and produces electricity by rotating the turbine blades. CHP turbines are mostly backpressure turbines. Fourthly, steam condenses after the turbine in the condenser, which acts as a heat exchanger heating up district heating water. The condensed water is preheated and pumped again into the boiler tube walls to vaporize.

The Rankine cycle gains high thermal efficiency and allows wide fuel range, since the turbine components are separated from the combustion products. The steam parameters are excellent for industrial steam consumers. The maintenance costs are low, but the high-pressure equipment is expensive and requires large space. The electrical efficiency of small-scale steam turbines is low, only 10…20 % and it decreases in part-load operation. (Arena, Di Gregorio and Santonastasi, 2010) Moreover, the Rankine cycle starts up slowly compared to engines and gas turbines. (Ismail, Moghavvemi and Mahlia, 2013)

2.1.5 Organic Rankine Cycle

Organic Rankine Cycle (ORC) can be applied in small and medium scale biomass CHP. Other common applications include geothermal energy, solar power plants and waste heat recovery. Organic Rankine cycle plants have been demonstrated and they are now commercially available (Schuster *et al.*, 2009).

ORC functions similarly to the conventional Rankine cycle, but water is replaced with an organic fluid, for instance ammonia, heptane, pentane, R134a, methanol, benzene or toluene (Tchanche *et al.*, 2011). The fluid is selected according to the fluid parameters, availability, cost and environmental performance (Quoilin *et al.*, 2013). Additionally, safety and chemical stability are considered. The fluid parameters include latent heat, molecular weight, freezing point and saturation curve. (Vélez *et al.*, 2012) Figure 8 shows the different saturation curves for typical ORC fluids.

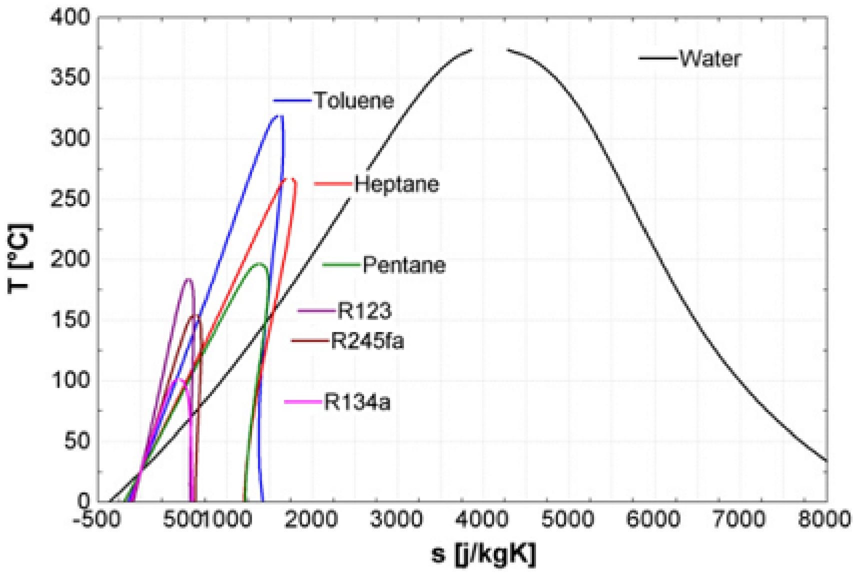


Figure 8. T-s diagram of water and typical ORC fluids. (Quoilin et al., 2013)

The main process consists of an evaporator (boiler), expander, condenser and feed pump (Figure 9). Adding a recuperator, economiser and preheater increases the efficiency, complexity and cost of the ORC plant. In the evaporator, the flue gases of combustion heat up the working fluid. The energy is converted into electricity in the expander. Heat is recovered in the condenser, where hot water is produced. The recuperator preheats the liquid before the evaporator. The preheater can receive heat from both recuperator and economiser. (Quoilin *et al.*, 2013)

ORC defeats steam Rankine cycle in small scale. ORC process is simpler than the Rankine process. A superheater is unnecessary, as the working fluids remains superheated after the expansion, preventing the corrosion of the turbine blades. Additionally, lower pressure and temperature and higher fluid density makes the components smaller and simpler. Lower boiling point of the working fluid enables low-temperature heat recovery. (Quoilin *et al.*, 2013)

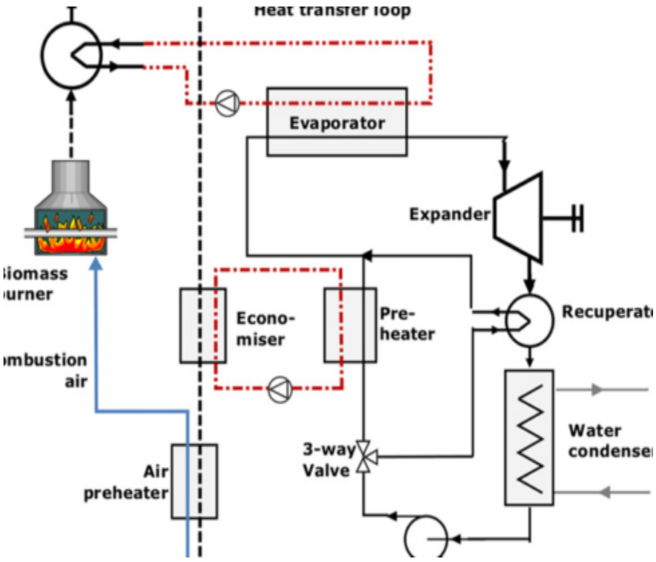


Figure 9. Working principle of a biomass CHP ORC system. (Quoilin et al., 2013)

The disadvantages compared to steam cycle are the following. ORC has lower efficiency. The working fluids feature smaller vaporization enthalpy than water, which increases energy consumption of the pump. The working fluid costs more than water. Additionally, it can be hazardous to the environment, flammable and chemically unstable. (Quoilin *et al.*, 2013)

2.1.6 Fuel cell

Fuel cells convert gaseous fuel to electricity. (Choudhury, Chandra and Arora, 2013) According to Ud Din and Zainal, low temperature fuel cells only operate with hydrogen and methanol. Thus, the fuel cell options for product gas from biomass gasification are molten carbonate fuel cell (MCFC) and solid oxide fuel cell (SOFC). SOFC poses more advantages than MCFC in gasification application. SOFC has the same operating temperature as gasification, although the product gas has to be cleaned first. Product gas impurities affecting the fuel cell are particulates, alkali metals, tar, halides, sulphur and nitrogenous species. In addition to product gas, SOFC can also run on bioethanol, biogas and bio-oil based hydrogen. (Ud Din and Zainal, 2016)

Figure 10 presents the schematic of a SOFC. A fuel cell comprises of three components: anode, cathode and an electrolyte. SOFC involves an oxide-ion conducting ceramic material electrolyte (Choudhury, Chandra and Arora, 2013). The operation principle is the following. Fuel gas is fed to the anode and an oxidant to the cathode. They disperse over the surface of the electrodes and electrons flow from the anode to the cathode. The electrons react with oxygen at the cathode. Resulting oxygen ions flow to the anode trough the electrolyte. Once they reach the anode, the ions react with the fuel forming water and carbon dioxide and releasing electrons. Thus, the fuel cell produces an electrical current. (Ud Din and Zainal, 2016)

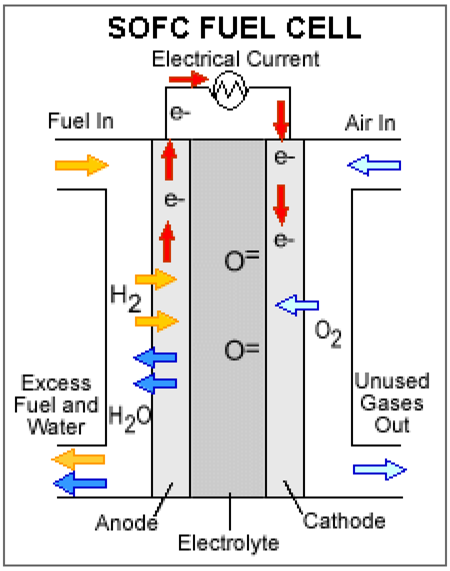


Figure 10. SOFC fuel cell. (Ud Din and Zainal, 2016)

Fuel cells are operated electrochemically, and they are liberated from the Carnot cycle and its maximum efficiency limit. Thus, they reach high electrical efficiencies. (Ud Din and Zainal, 2016) The electrical efficiencies of solid oxide fuel cells range from 45 to 60 % (Salomón *et al.*, 2011; Dodds *et al.*, 2015). The higher electrical efficiencies (over 55 %) are achieved by pairing the fuel cell with a microturbine. The electrical efficiency of SOFC running on product gas from an autothermal gasifier is approximately 38 %. (Karl *et al.*, 2009) High temperature fuel cells like SOFC achieve a clean combustion process and utilize also other fuels than H_2, as the fuels reform into H_2 in the fuel cell. (Choudhury, Chandra and Arora, 2013) The main disadvantages are high costs and moderate start-up time (Ismail, Moghavvemi and Mahlia, 2013).

2.1.7 Stirling engine and steam engine

Stirling engines are external combustion engines. A working fluid, such as air, helium or hydrogen, brings the heat from the primary conversion to the engine. Stirling engine comprises of an engine, heater, cooler and regenerator (Figure 11). Additionally, an auxiliary heat exchanger can be installed. The heat transfer to the fluid happens in a heat exchanger called heater. The cooler absorbs heat from working fluid and transfers it to the atmosphere with the help of a coolant. Only part of the fluid is cooled and the regenerator stores the extra heat. (Thombare and Verma, 2008)

Stirling engines can be classified according to operation mode, cylinder coupling, piston coupling, gas coupling and liquid coupling. There are three main cylinder couplings in Stirling engines: alpha, beta and gamma. (Thombare and Verma, 2008)

The Stirling engine is a proven technology, although unusual for biomass conversion. The advantages comprise of low maintenance requirement, low noise and high thermal efficiency. (González *et al.*, 2015) Stirling engine size ranges up to 75 kW_e (Salomón *et al.*, 2011). CHP with Stirling engine allows lower grade fuels, as the flue gas is detached from the engine. (Eames, Evans and Pickering, 2016)

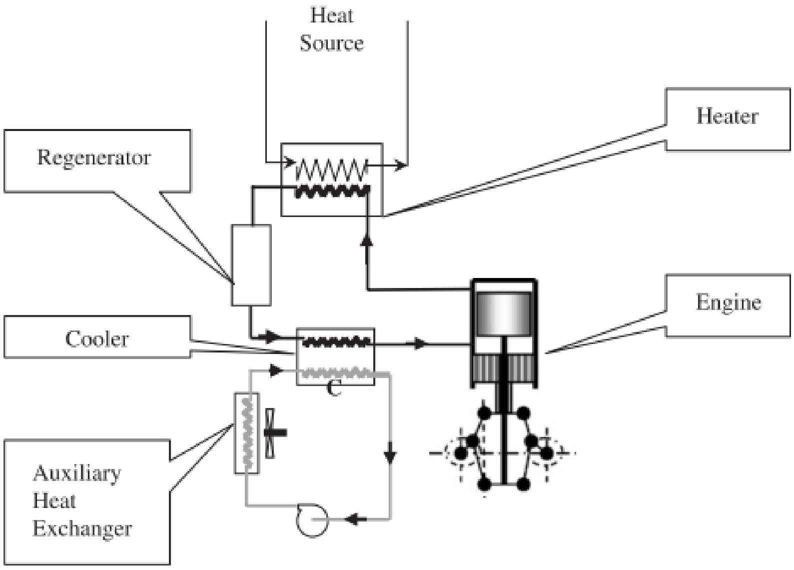


Figure 11. Stirling engine and heat exchangers, arrows depict heat flows. (Thombare and Verma, 2008)

Steam engines operate according to the same principle as the Rankine cycle, only the steam turbine is replaced with a steam engine. Steam engines can utilize many kinds of fuels similarly to the steam turbine Rankine cycles. Steam engines produce 20…5000 MW electricity. They obtain electrical efficiencies of 6 to 20 percent. The investment costs are equal to the Rankine cycle. The technical limitations with advanced steam conditions (superheating), noise and high maintenance requirement constitute the disadvantages of the steam engine. Consequently, steam turbines, internal combustion engines and electric motors have widely replaced steam engines. (Salomón *et al.*, 2011)

2.1.8 Comparison

According to Arena et al. the main power generation device options for product gas include Rankine cycle, gas turbine (internally or externally fired) and gas engine. Gas engines can reach highest electrical efficiencies up to 28 %. All of the other options show decreased efficiencies in partial load, although gas turbines (GT) and micro gas turbines (mGT) reach high efficiencies in full load. Steam turbines (ST) yield very low efficiencies at small scale. However, steam engines (SE) acquire the lowest efficiencies.

Table 1. Comparison of CHP technologies, own construction from following sources. (Arena, Di Gregorio and Santonastasi, 2010; Salomón et al., 2011; Ismail, Moghavvemi and Mahlia, 2013; Streimikiene and Baležentis, 2013)

	Scale, kW_e	*η_e, %*	*$\eta_{e,pg}$, %*	*$\eta_{overall}$, %*	*Specific cost, €/kW*
ICE	2-	25-45	13-28	80-90	800-1800
(m)GT	25-	11-40	15-25	70-90	800-1700
ST	500-	20-30	10-20	85-93	1500
ORC	2-10000	10-30	-	85	4500
SOFC	5-10000	45-60	-	80	1000-1500
Stirling	1-75	15-40	-	80-90	3500
SE	20-5000	6-20	-	85-95	1500

The maintenance intervals for ICE are short and expensive, while the other options are characterized by long maintenance intervals and high availability. On the other hand, gas and steam turbines are expensive investments. Both ICE and internally fired gas turbines face challenges with the product gas impurities. (Arena, Di Gregorio and Santonastasi, 2010)

Table 1 demonstrates the scale, power conversion efficiencies, η_e, efficiencies with product gas as a fuel, $\eta_{e,pg}$, and overall efficiencies, $\eta_{overall}$, of different CHP technologies. According to Kikuchi et al. the conversion efficiencies remain stable, as the technologies are well-developed. ORC achieves higher efficiency than ST in the 200 to 21000 kW range. Stirling engines are adopted for micro scale power generation. Figure 12 presents the electrical efficiencies of different technologies as a function of the power capacity. (Kikuchi *et al.*, 2015) The electrical efficiencies of Stirling engines in Figure 12 are much lower than the other technologies due to the smaller scale. The other technologies would also obtain lower efficiencies in smaller capacities.

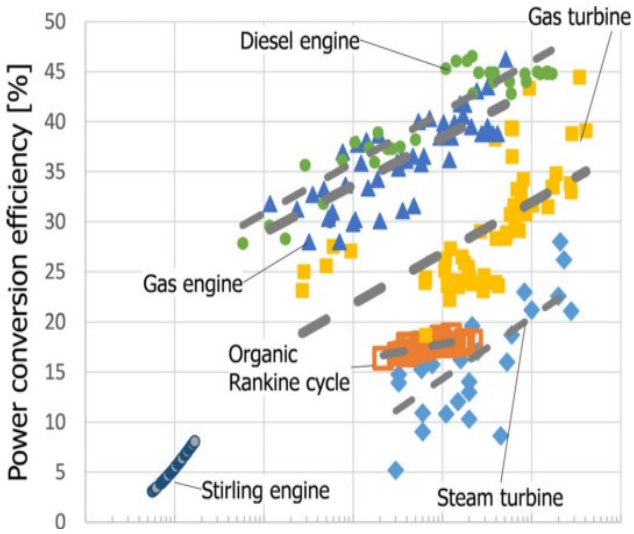


Figure 12. Power conversion efficiency of different CHP technologies. (Kikuchi et al., 2015)

2.2 Gasification technologies for small-scale CHP production

2.2.1 Fixed bed gasifiers

Fixed bed gasifiers can be divided into two types: updraft (countercurrent) and downdraft (concurrent) (Molino, Chianese and Musmarra, 2016). These can also be called moving bed reactors (Giltrap and Barnes, 2009; Basu, 2013b). Additionally, crosscurrent type is presented in some references (Basu, 2013b; Bocci *et al.*, 2014). The main technology for combined heat and power production is the downdraft gasifier, as the product gas contains little tar and thus the gas requires less cleaning before an engine or a gas turbine. (Basu, 2013a)

Biomass-fired fixed bed gasifiers produce ash, which contains the minerals of the biomass. The ash particles are very fine and often exit the gasifier with the product gas, which induces difficulties in energy production in internal combustion engines or gas turbines. Additionally, the ash contributes to particle emissions in the flue gas. (Asadullah, 2014b)

In the downdraft gasifier, feedstock is fed at the top of the gasifier and gas is collected under the grate at the bottom of the gasifier. Air flows in the same direction as the product gas. The gasifier has fairly distinguished zones for drying, pyrolysis, combustion and gasification (Figure 13). Ash drops off the gas flow at the bottom of the gasifier.

Downdraft gasifiers gain low tar concentration in the product gas due to the high temperature combustion zone, which the gas passes. To reach even lower tar concentration, the air can be staged into two stages. The charcoal bed contributes to high char conversion and low ash in the product gas. (Martínez *et al.*, 2012) Downdraft gasifiers gain high reliability (Molino, Chianese and Musmarra, 2016).

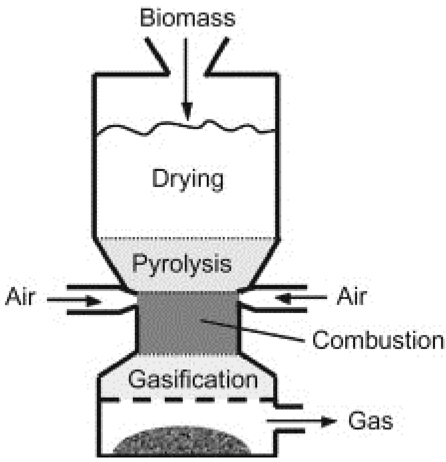


Figure 13. Downdraft gasifier. (Basu, 2013a)

The disadvantages of downdraft gasifiers are limited scale-up and demanding feedstock quality requirements (Giltrap and Barnes, 2009). The typical capacity of the downdraft gasifier extends to 200 kW_e (Hrbek, 2016). This ensures the entire combustion zone contains sufficiently oxygen (Giltrap and Barnes, 2009) and the heat transfer operates as designed. The particle size of the feedstock is limited (Martínez *et al.*, 2012) and has to be uniform (Molino, Chianese and Musmarra, 2016). Downdraft gasifiers require low moisture content fuels (Molino, Chianese and Musmarra, 2016) max 25 % moisture on wet basis (wb) and max 6 % of ash on dry basis (db) (Basu, 2013b).

There are three main types of downdraft gasifiers, which are distinguished by the air flow: open top, conventional and Imbert gasifiers. In the open top gasifier, the air flow is unbounded. In the closed top throatless gasifier air is also fed at the top of the gasifier. In the Imbert gasifier, a throat is situated close to the grate and air is blown straight into the combustion zone of the gasifier. (Martínez *et al.*, 2012)

According to Vakalis and Baratieri the existing downdraft gasifier designs include Imbert Hourglass, V-Hearth, Constricted Flat Plate, Straight Reduction Tube, Stratified Downdraft, Multipoint air injection, Buck Rogers and J-tube. The main differences are in the throat, grate and air nozzles. (Vakalis and Baratieri, 2015)

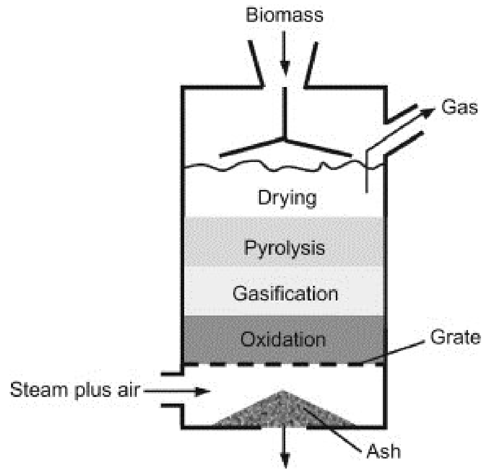


Figure 14. Updraft gasifier. (Basu, 2013b)

In an updraft gasifier (Figure 14) the gasification medium moves upward. Biomass is fed to the reactor from the top and it moves downward. The product gas leaves the reactor at the top. Ash drops through the moving grate. The zones of gasification are also fairly well-defined in updraft gasifiers. (Basu, 2013b)

The advantages of an updraft gasifier are simple construction, wide feedstock range and high efficiency. The feedstock can contain ash up to 25 % db and the moisture content is tolerated up to 60 % wb. Updraft gasifiers obtain high cold gas efficiency, since the gasifier utilizes the heat from the combustion zone efficiently. (Basu, 2013b).

The major disadvantage of an updraft gasifier is the high tar content of the product gas, as the pyrolysis products are mixed with the product gas. Thus, the product gas can only be applied to direct combustion (Giltrap and Barnes, 2009). Tar contains more than 20 % of the energy, which is lost in cleaning. Moreover, tar cracking catalysts may not activate as the product gas energy does not suffice. (Molino, Chianese and Musmarra, 2016) Updraft gasifiers require moving grates, to avoid permanent paths for gases, which complicates the construction. (Molino, Chianese and Musmarra, 2016)

Manufacturers and researchers have developed and patented several new small-scale gasification technologies. These include rising co-current, hot char bed, double-fired bed and heat pipe reformer. (Vakalis and Baratieri, 2015) The feasibility study of this thesis focuses on the Gasgen downdraft gasifier developed by VTT.

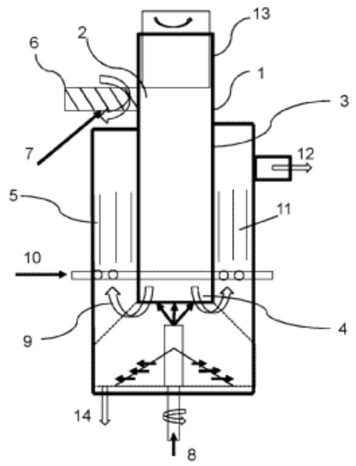


Figure 15. Gasgen gasifier sketch in the patent application. (FI 126357, 2016)

Gasgen technology integrates in-situ tar decomposition with fixed bed gasifier. The feedstock enters at the upper part of the gasifier and passes the pyrolysis zone (Figure 15). The final gasification occurs in the lower part of the gasifier. Primary air is fed countercurrently from the bottom of the gasifier (8). The product gas passes a catalyst layer (11) and the tars are reformed. The reforming air is fed at the sides of the gasifier. (FI 126357, 2016) Wide feedstock selection and scalability differentiate the Gasgen technology from the other downdraft designs. An earlier version, the Novel gasifier was demonstrated in Kokemäki, although it reached no commercial status. (Kurkela *et al.*, 2000, p. 33) (Kurkela and Kurkela, 2009, p. 19)

2.2.2 Fluidised bed gasifiers

Two types of fluidised bed reactors suit small-scale biomass gasification: bubbling fluidised bed gasifier (BFB) and dual fluidised bed (DFB). BFB is more common than DFB, which has only been piloted. (Corella, Toledo and Molina, 2007). Circulating fluidised bed gasifiers are only applied in larger scale for economic reasons (Kirkels and Verbong, 2011).

In a BFB gasifier, bed material and feedstock are fluidised with the gasifying medium (Figure 16). The typical bed materials include sand, dolomite and olivine. The BFB reactor contains no moving components. Still, the mixing and feedstock carbon conversion to gas is efficient, as the bed behaves like a boiling liquid. The temperature remains rather low, 700…900 °C. The tar content of the product gas lies between updraft and downdraft gasifiers. Catalytic bed materials reduce tar concentration. The disadvantages of BFB compared to fixed bed gasifiers include more complicated operation, abrasion of the reactor and thus higher particulates concentration in the product gas. (Bocci *et al.*, 2014)

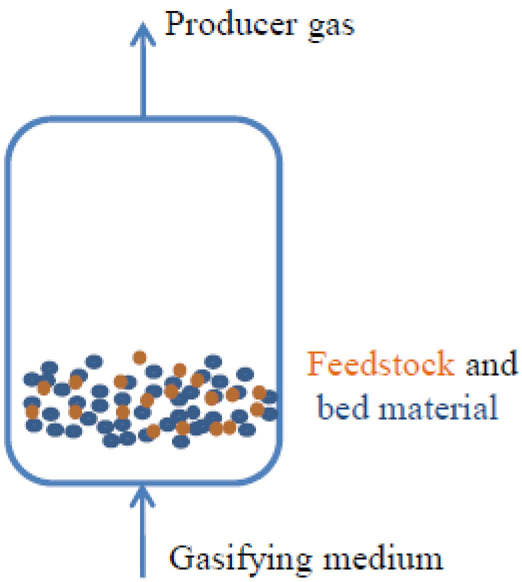


Figure 16. Bubbling fluidised bed gasifier schematic.

According to Molino et al. BFB advantages include feedstock and load flexibility as well as easy start-up and shut-down. The disadvantages comprise loss of carbon in the ashes as well as high investment and maintenance costs. Heterogeneous materials require pre-treatment. Moreover, biomass feedstock calls for low temperatures to prevent ash agglomeration. (Molino, Chianese and Musmarra, 2016)

Dual fluidised bed gasifiers are comprised of two main parts: a combustion chamber called the combustor and a gasifier chamber (Figure 17). Steam usually acts as the gasifying agent and air oxidises the char from the gasification in the combustor. The bed material transfers the heat to the gasifier facilitating the endothermic water shift reaction, which requires temperatures over 800 °C. (Corella, Toledo and Molina, 2007)

DFB gasifiers produce the high-quality product gas, as no nitrogen and high percentages of hydrogen are present in the product gas. The disadvantages include complicated design and consequently high price. An external energy source secures the high temperature in the gasifier and enables produce steam. Moreover, the conversion of steam into hydrogen rarely exceeds 10 percent and, as a result, most of the energy is lost heating up the steam. (Corella, Toledo and Molina, 2007)

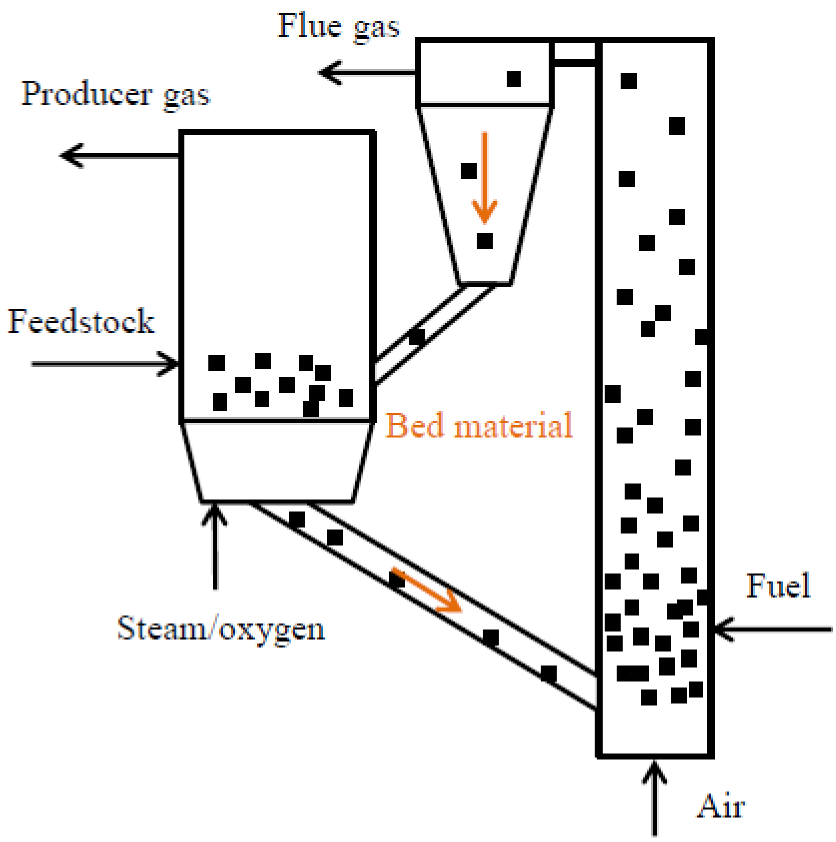


Figure 17. Dual fluidised bed gasifier schematic.

2.3 Biomass as a fuel for gasification and internal combustion engine

2.3.1 Available biomasses

Biomass is defined as "material of biological origin excluding material embedded in geological formations and/or fossilized". Biomass subsumes dedicated energy crops, agricultural crops and trees, aquatic plants, algae, forestry and agricultural residues. (ISO SFS-EN, 2014) Photosynthesis stores solar energy in biomass, which can be converted into heat and electricity by gasification.

The criteria for gasification feedstock comprise of availability, as well as physical and chemical characteristics (Figure 18). The physical characteristics consist of humidity, density, size and shape of the feedstock. Dry feedstocks induce best gasifier efficiencies. The density affects transportation costs. Uniform size and shape mitigate feeding the biomass to the reactor. Drying and shredding may improve the physical characteristics of the feedstock.

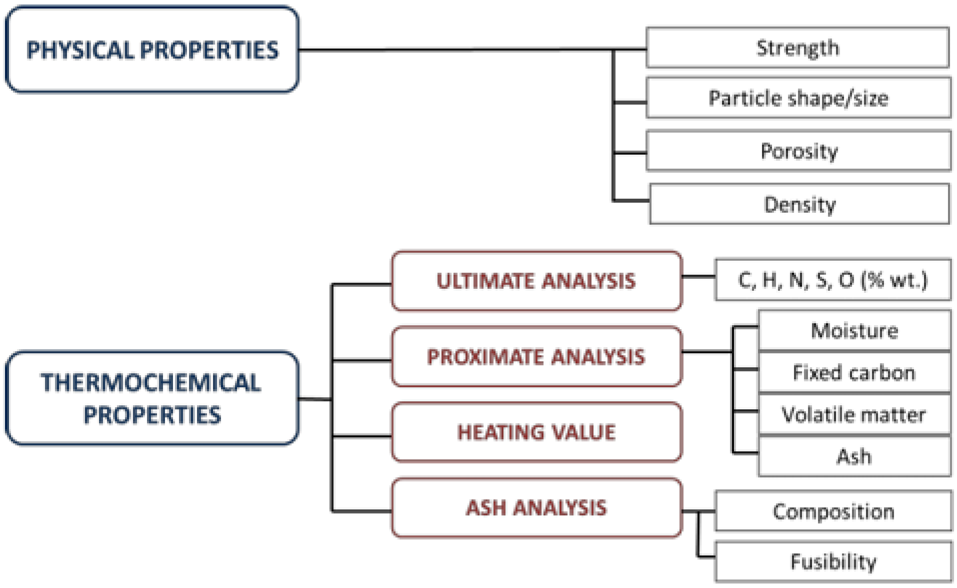


Figure 18. Biomass properties affecting gasification. (IEA Bioenergy, 2016)

The chemical characteristics are inspected with proximate and ultimate analysis, which yield the chemical composition, and thus the lower heating value (LHV) can be calculated. Volatile components, ash, tar, sulphur, chlorine and alkali content affect the feedstock suitability for gasification. High ash content indicates problems with sintering, agglomeration, deposition, erosion, corrosion and product gas cleaning. Tar complicates product gas cleaning. (Bocci *et al.*, 2014)

The characterization of biomass is highly standardised. Over 20 ISO standards cover solid biofuel specifications and classes, determination of different characteristics and terminology. The solid biofuel classes include wood pellets, wood briquettes, wood chips, firewood, non-woody briquettes and non-woody pellets. The standardised tests involve determination of different elements, particle size, bulk density, mechanical durability (pellets and briquettes), as well as ash, volatile matter and moisture content. (ISO, 2016)

Biomass feedstocks for small-scale fixed bed gasifiers consist of different biomass wastes, such as shells, prunings, straws, agro-industrial residues and energy crops. (Bocci *et al.*, 2014) Agricultural residues hold high ash contents. Coconut shells and maize cobs are documented well, as well as palm kernel shells. Most of the residues contain close to 10 percent ash, although for example rice husks contain 20 % ash. (Asadullah, 2014a)

In Finland, the main available feedstocks for gasification are wood chips and forest industry by-products (Salomón *et al.*, 2011). In France and thus in Europe, the feedstocks for gasification comprise beech, spruce, poplar, eucalyptus, wheat, triticale, fescue, miscanthus and switchgrass (Da Silva Perez *et al.*, 2015). In Japan, cedar wood (Aljbour and Kawamoto, 2013) and bamboo (Zheng *et al.*, 2016) gasification have been studied. In USA, corn stover, switchgrass, wheat straw and wood were tested for gasification (Carpenter *et al.*, 2010).

Lenis et al listed the characteristics of the following fast-growing wood species: acacia, eucalyptus, two pine species and Gmelina arborea, which can be utilized as energy crops in Colombia (Lenis, Osorio and Pérez, 2013). In Africa, the potential gasifier fuels involve eucalyptus, pines, cedar wood and sugarcane bagasse (Mosiori *et al.*, 2015). In China, straw from food crops, like rice, wheat, corn and oil crops is available. Additionally, logging residues and log processing residues could be utilized for gasification. (Yanli *et al.*, 2010) Table 2 demonstrates the properties of various available biomasses.

Table 2. Comparison of chemical properties of feedstocks. (Lenis, Osorio and Pérez, 2013; Alakangas et al., 2016; Zheng et al., 2016)

Feedstock	*Moisture content*	*Content on a dry basis, m-%*					*LHV (db)*
	m-%	C	H	N	S	Ash	MJ/kg
Logging residue chips	50	51.3	6.1	0.4	0.02	2.4	19.3
Plywood edges	21.9	50.6	5.9	0.1	0.01	0.96	19.1
Bark	50	49.9	5.9	0.4	0.03	2.3	18.5
Sawdust	50	51	5.99	0.08	0	0.1	19.03
Reed canary grass	13	45	5.7	1.4	0.14	8.85	17.13
Straw	15	47.3	5.87	0.7	0.16	4.8	17.65
Eucalyptus	8.54	53.31	6.74	0.39	0.02	0.31	18.489
Bamboo	7.14	44.83	5.96	0.35	0.15	1.49	18.32

High-lignin agricultural biomass emerges as a potential small-scale gasification feedstock in Southeast Asia. The species include coconut, mango, olive, walnut, pistachio, cherry, peach, plum, apricot, almond and stone fruit, which are grown for instance in India, Indonesia, China, Philippines, Sri Lanka and Thailand. The drupe endocarp biomass contains more energy than cellulose-based biomass and less ash than many other agricultural residues. The dual-use of cropping retains food security, although the crops yield less energy than dedicated energy crops. The potential of these biomasses amounts to $4.1 \ldots 5.2 \times 10^8$ GJ before gasification efficiency of conversion. With CHP approximately 80 % of this energy can be utilized. (Mendu *et al.*, 2012)

2.3.2 Challenges

The technical challenges of biomass gasification range from the biomass supply chain and pretreatment to gas cleaning and cooling before the internal combustion engine. The collection and transportation of biomass is complex and costly. The biomass feedstock often requires pretreatment: drying, grinding or densification. The product gas contains impurities, such as particulates and tar, which require cleaning before power generation in an internal combustion engine. (Asadullah, 2014a)

The low energy density of biomass makes the transportation costly. (Bocci *et al.*, 2014) Pelletizing or briquetting can resolve the issues with low density. Additionally, the biomass becomes more homogenous and the particle size more uniform, which reduces issues with fuel feeding into the gasifier. Briquetting machinery is less complex than pelletizing and thus more cost effective, although the bulk density remains a little lower than that with pelletizing. However, densification and sizing leads to smaller surface area for the gasification reaction and shorter residence time in the reactor. (Asadullah, 2014a)

Moisture and ash content determine the suitability of biomass feedstocks for different gasifiers. Firstly, high moisture content raises problems with downdraft gasifier operation. Conventional downdraft gasifiers require moisture content under 25 % (Basu, 2013b). In updraft gasifiers, the moisture content increases the energy requirement for gasification, which compromises the product gas quality. (Brammer and Bridgwater, 1999) Drying solves the problem with high moisture content. Chapter 2.3.3 covers biomass drying from a small-scale viewpoint. Secondly, high ash content complicates the gasifier operation. Especially downdraft fixed bed gasifiers experience problems with high ash content feedstock (Basu, 2013b). The ash melting point determines the maximum operating temperature of the gasifier (Asadullah, 2014a).

Product gas quality affects engine operation. Engines require a certain percentage of burnable gas. Additionally, tar, dust and corrosive gases are limited. (Asadullah, 2014a) The main impurities causing problems are tar and particulates. Moreover, nitrogen, sulphur and chlorine compounds cause corrosion. The engines designed for natural gas require modifications in order to run on product gas. (Martínez *et al.*, 2012) Typical areas of concern include the fuel gas pipe control line, gas heat exchanger, turbo charger, intercooler, air conditioning, air-fuel ratio control, safety and engine oil (Brandin et al., 2011, p.66-67). Gas cleaning and reactor design affect the gas composition. Gas cleaning is described in chapter 2.3.4 and different reactor designs in chapter 2.2.

2.3.3 Drying of biomass

Most biomass feedstocks require drying from 30…60 mass percent moisture to 10…15 percent moisture content (Fagernäs *et al.*, 2010). Biomass drying is based on evaporation. Drying integrates two simultaneous processes: heat transfer to the particle and mass transfer of water out of the particle. Heat transfers to the particle by conduction, convection or radiation. Inside the particle, heat is conducted. Drying involves three distinct periods: heating up, period of constant drying rate and period of falling drying rate.

Dryer choice depends on biomass properties, dryer integration to the gasification plant, energy efficiency, dryer performance, emissions and fire or explosion risks (Fagernäs *et al.*, 2010). Biomass dryers are classified by heat transfer type (direct/indirect), mode of feeding (batch or continuous) and heat source (air, flue gas, sun, steam). (Asadullah, 2014a) Dryer integration with gasification CHP depends on the power producing equipment. With an ICE, the flue gases can act as the drying medium or heat air. Steam turbine configurations may allocate part of the steam for biomass drying.

Figure 19 presents the heat sources for drying in a biomass gasification CHP plant. They include the product gas cooling, engine cooling and flue gas heat recovery, as well as heat recovered from a steam cycle. (Brammer and Bridgwater, 1999) A boiler recovers the heat from the engine flue gases and produces hot water or steam. The condenser can produce hot water for drying. Steam boilers are also known as steam generators or heat recovery steam generators.

The following properties of biomass affect the dryer selection: size, density, friability, moisture content and dust emissions. (Brammer and Bridgwater, 1999) Rotary dryers accept large and variable particle sizes, while belt and flash dryer require smaller particle sizes (Fagernäs *et al.*, 2010).

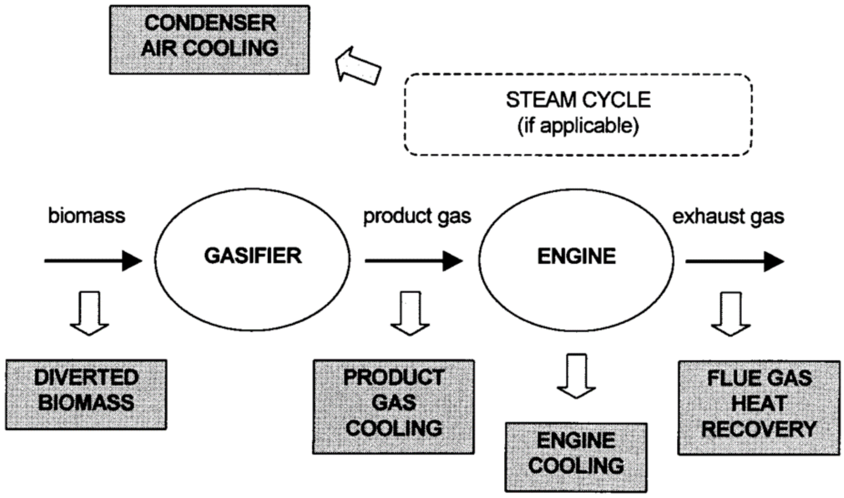


Figure 19. Sources of drying heat in a biomass gasification CHP plant. (Brammer and Bridgwater, 1999)

The thermal efficiency of a dryer indicates the ratio between the theoretical heat required for water evaporation and the net heat supplied to the drier. The theoretical energy consumption for water evaporation at 15 °C amounts to 2.48…2.57 GJ/tonne of water evaporated. The efficiency never reaches 1 as, the dryer also heats up the solids, heat diffuses to the surrounding air and warm humid exhaust leaves the dryer. (Brammer and Bridgwater, 1999)

Drying technologies for biomass gasification include

- batch through-circulation (perforated floor bin or silo)
- continuous through-circulation (band/rotary louvre)
- direct rotary (rotary cascade)
- indirect rotary (rotary steam tube)
- fluid bed (conventional/steam) and
- pneumatic conveying (steam). (Brammer and Bridgwater, 1999; Fagernäs *et al.*, 2010)

Asadullah also lists solar dryers and thermal screw dryers. Solar drying is cost-effective, but slow and the biomass degrades biologically during the process. Drying at the gasification plant reaches more stabile drying results, although it costs more. (Asadullah, 2014a)

Continuous dryers utilize the continuous heat sources of the gasifier CHP plant efficiently. However, batch drying equipment may be preferred duet to their economics. Continuous dryers are more expensive than batch dryers. (Brammer and Bridgwater, 1999)

The batch trough-circulation is an attractive option at small scales. Continuous trough-circulation dryers suit fragile materials. Rotary dryers serve medium to large scale, as they consume large quantities of drying medium. Steam as a drying medium is expensive and only feasible in large plants. Conventional fluid bed drying is a low-cost solution, but only applicable for small mean particle sizes and certain particle size range. (Brammer and Bridgwater, 1999)

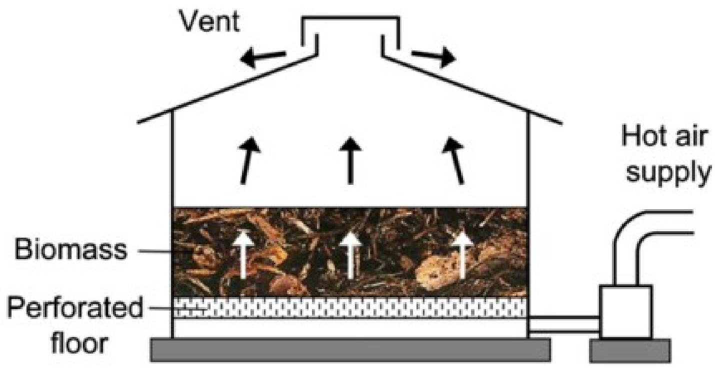


Figure 20. Perforated floor dryer. (Fagernäs et al., 2010)

The most common dryers for biomass are rotary and flash flue gas dryers. At small scales, the preferred technologies are low-cost perforated-floor drying (Figure 20) and band conveyors (Figure 21) heated with air or flue gases. Perforated floor dryers are best suited for small plants, although the dryness varies vertically. Perforated floor dryers are mostly operating in batch mode. Band conveyors are easy to control and produce uniformly dried feedstock. However, they require large spaces. The energy demand for band conveyors ranges between 4 and 5 MJ/kg$_{H2O}$. (Fagernäs *et al.*, 2010)

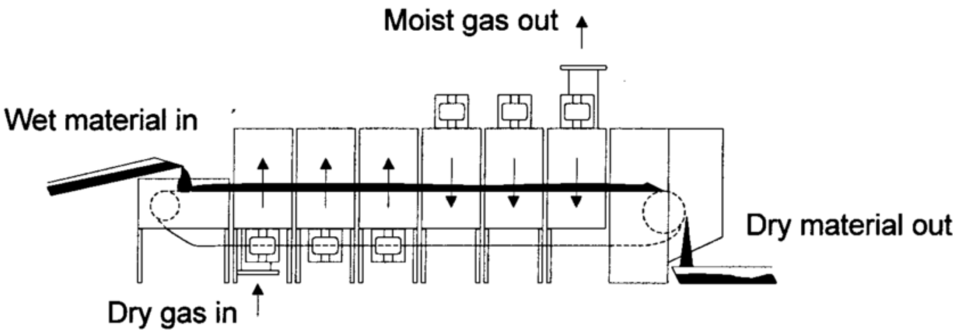


Figure 21. Band or belt conveyor dryer. (Brammer and Bridgwater, 1999)

The emissions of a dryer contain organic compounds. These are volatile organic compounds, condensable compounds and particulates. Low drying temperatures reduce the emissions. For example, fluid bed dryers and belt dryers operate in low temperatures. Filters remove particulates. While using steam as a drying medium, the condensate can be cleaned by means of precipitation and biological oxidation. (Fagernäs *et al.*, 2010)

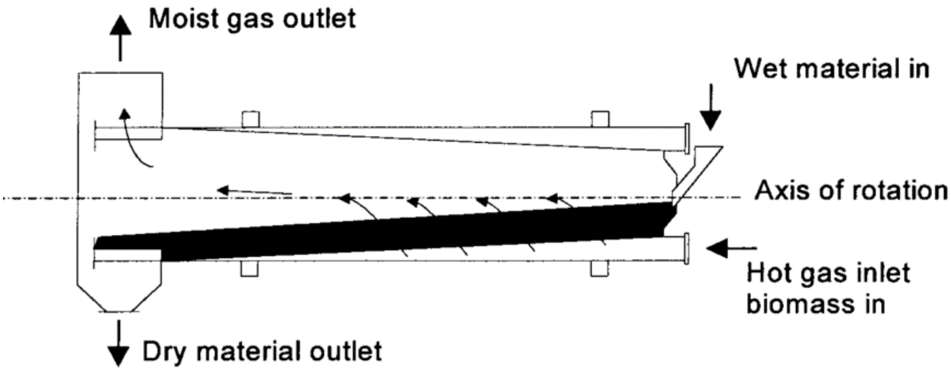


Figure 22. Rotary louvre dryer. (Brammer and Bridgwater, 1999)

Dust cloud or the ignition of combustible gases can cause a fire or explosion. The risk is higher with dryer medium oxygen content over 10 %-vol. Thus, air as a drying medium requires lower temperatures to reduce the risks. Steam or other inert drying medium reduces the risk of fire or explosion. (Fagernäs *et al.*, 2010)

According to the economic calculations of Brammer and Bridgewater, the optimum small-scale drying technology for gasification and IC engine setup under 2 MW_e is a rotary dryer (Figure 22) with burner above 1 dry tons per hour biomass feed rate and a band dryer in smaller scale. The efficiency of the rotary dryer with burner is approximately 75 % and that of the band dryer or rotary dryer without burner is approximately 66 %. (Brammer and Bridgewater, 2002)

2.3.4 Product gas cleaning

The raw product gas contains contaminants, such as tars, particulates, ammonia and HCl, which require cleaning before electricity generation devices. The high costs of the cleaning are acceptable, as gasification converts biomass to product gas efficiently. The product gas cleaning technologies can be divided into primary and secondary methods. The primary methods take place inside the gasifier and the secondary methods downstream of the gasifier. Downstream gas cleaning (secondary) comprises hot and cold cleaning. (Bocci *et al.*, 2014)

Primary gas cleaning subsumes bed additives, as well as reactor design and optimization. The common additives, such as dolomite, olivine and nickel-based compounds act as catalysts or sorbents. (Bocci *et al.*, 2014) Gasgen technology integrates in-situ tar decomposition, which is considered a primary gas cleaning method, into fixed bed gasifiers.

Secondary hot cleaning devices comprise cyclones, tar cracking and high temperature filters. Cyclones separate the particulates and char. They are widely applied in fluidised bed reactors, as the product gas contains high amounts of particulates and char. Tar cracking devices reduce the amount of tar and alkali in the product gas. They may utilize a catalyst to enhance the tar cracking reactions. High temperature filters, which are made of ceramic or metallic materials, remove sulphur, chlorine and fine particles. (Bocci *et al.*, 2014)

Secondary cold gas cleaning includes low-temperature (150…250 °C) bag and sand filters as well as wet scrubbers. Filters remove particulates. Wet scrubbers operate at 25…50 °C temperatures and remove particulates, tar and nitrogen compounds. Unfortunately, the wet methods require water treatment facilities. Moreover, energy is lost, as the gas cools down. (Bocci *et al.*, 2014) Water treatment can be avoided by using organic solvents, which can be burned to provide heat for gasification, but they are expensive (Asadullah, 2014b).

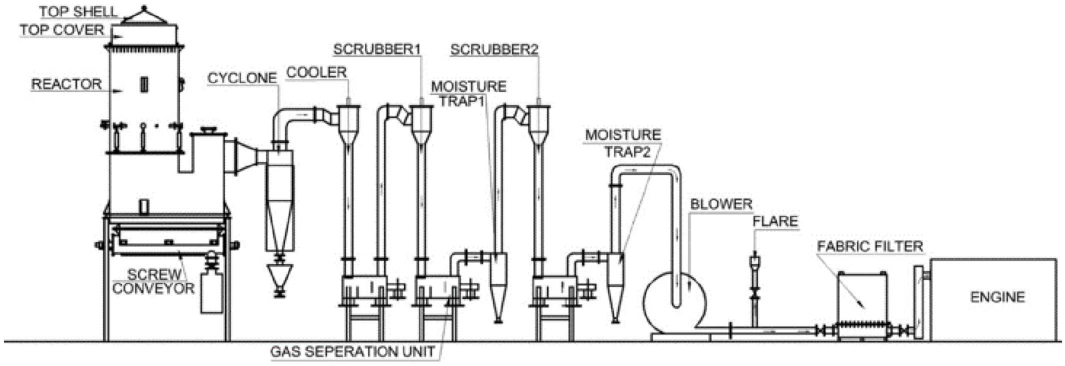


Figure 23. Plant layout of a 100 kWe biomass gasification plant. (Dasappa et al., 2011)

For example, in a 100 kW_e biomass gasification power plant in Karnataka, India, the product gas cleaning and cooling consists of a cyclone, cooler, two scrubbers, chiller and filter (Figure 23). Activated carbon cleans the product gas originating from woody biomass. (Dasappa *et al.*, 2011)

2.4 Market perspectives

2.4.1 Global overview

In 2014, 433 TWh of power was generated from biomass, the installed capacity reaching 93 GW (REN21, 2015). According to International Renewable Energy Agency (IRENA), wood gas, the gas retrieved from wood chip gasification, provided 1 % of the installed bioelectricity capacity in the world in 2010 (IRENA, 2012, pp. 21–26). This would amount to approximately 900 MW of gasification capacity connected to the grid.

Out of all renewable energy supply, solid biofuels have grown the slowest between 1990 and 2013. Biogas has grown 10 %. Solar and wind seem to grow much faster due to the very low capacities in 1990. (IEA Statistics, 2015) Bioelectricity production grows, as efficient CHP plants are installed. (Observ'ER and Fondation Énergies pourle Monde, 2013) Table 3 compares the shares of bioelectricity, their growth rate and other economic data on Japan, UK, Finland, Austria and Germany.

Table 3. Electricity from biomass and country specific economic and electricity consumption data. (Observ'ER and Fondation Énergies pourle Monde, 2013)

	Japan	*UK*	*Finland*	*Austria*	*Germany*
Electricity from biomass 2012, %	3.1	4.2	15.4	6.9	6.7
Electricity from biomass, TWh	28.8	12.9	10.5	4.3	36.5
Annual growth rate 2002-2012, %	9	11.6	1	11.6	22.8
Population, million	127.2	63.1	5.4	8.4	81.3
Electricity consumption, kWh/capita	0.26	0.18	0.4	0.22	0.22
Gross electricity consumption, TWh	1056.6	374.6	87.8	71.2	603.5

Government policies drive the development of renewable energy. At least 164 countries have released renewable energy targets. The development has linked the earlier separate policies of electricity, heat and transport sectors. Municipalities ambitiously promote renewable energy. Developing countries invest in renewable power more than developed countries. (REN21, 2015, p. 79)

Combustion and Rankine cycle dominate the small-scale CHP markets. Gasification and anaerobic digestion provide advantages for CHP, as the electrical efficiencies of internal combustion engines, fuel cells and gas turbines are higher than that of the small-scale steam turbine. Anaerobic digestion is already commercially available and widely employed. Most of the CHP technologies are commercial independent from biomass conversion. Several characteristics have prohibited the full commercialisation of gasification. They include high cost, complexity and technical and operational challenges, which reduce reliability and availability. In Norway, the only profitable biomass CHP option was biogas engines in 2011 conditions. (Kempegowda, Skreiberg and Tran, 2012)

The main countries producing electricity from biomass are the United States, Brazil, Germany, Japan, UK, Finland, Sweden, Italy, Poland and the Netherlands. In Northern Africa, no electricity is produced from biomass. Also Sub-Saharan Africa, Middle-East, Australia, Central America and Western Asia hold minor shares of bioelectricity. (Observ'ER and Fondation Énergies pourle Monde, 2013)

Kalt and Kranzl estimated the different bioenergy options for Austria in order to reduce greenhouse gas (GHG) emissions and increase the share of renewable energy. They found that plant size affects the results due to economics of scale. Small-scale gasification CHP had higher price of electricity than small-scale biogas CHP. As the heat revenues are taken into account, gasification becomes the most expensive solution in 600 kW_e size. (Kalt and Kranzl, 2011)

In the UK, many biomass CHP projects have failed in the project development phase. The main explanations are high costs and the several compulsory agreements. Planning permissions are strenuous to obtain. Lenders require long-term feedstock supply contracts, which prevent the benefits of feedstock price decreases. Agreements with heat customers are prohibited by retrofitting costs, lack of advisory personnel and fear of monopoly. Long-term electricity contracts are also required. The high costs of installation may be insufficiently compensated, if small electricity suppliers fall outside the subsidies. (Wright, Dey and Brammer, 2014)

König assessed the cost efficiency of bioenergy options for GHG reduction in Germany. Gasification and gas engine CHP has significant shares of heat and power generation, if the GHG emission reduction targets are ambitious (half of the 1990 level in 2030). In the scenario, biomass competes with conventional energy production without incentives for renewable technologies. In this scenario, the energy generation from biomass surpasses the other scenarios. (König, 2011)

The growth of small-scale gasification has been rapid in South Tyrol region in Italy due to the high availability of forestry and agricultural residues and increased feed-in tariffs. Additionally, the high performance and stability of the new concepts affected the investment decisions. The technologies gaining market share are highly automated, modular and run on restricted spectrum of biomass feedstocks. (Vakalis and Baratieri, 2015)

Yagi and Nakata found that logging residues could supply gasification CHP in Japan if biomass prices decrease due to technological learning and new methods of collection. Today, mainly waste wood is utilized, since forest biomass has high transport costs. Additionally, Japan promotes bioenergy to create jobs, enhance competitiveness, secure energy supply and activate agriculture, forestry and fishery. (Yagi and Nakata, 2011)

Moon *et al.* compare biomass combustion with steam turbine and gasification coupled with gas engine considering the Korean energy policies. They conclude that the biomass gasification coupled with gas engine is more profitable and less sensitive to heat price changes than the conventional combustion system in the 0.5…5 MW_e scale. The study also shows that the heat sales of CHP production improves the profitability. (Moon, Lee and Lee, 2011)

Reducing coal-based electricity share and air pollution as well as providing electricity to tackle the shortage problems motivate biomass gasification in China. Applications below 200 kW_e utilize downdraft gasifiers and generate power by gas engines. Below 3 MW scale bubbling or other fluidised bed gasifiers are applied. Especially rice husk gasification has been developed. The total capacity of biomass gasification in 2012 neared 100 MW. The energy administration states that gasification development in rural areas belongs to their three biomass utilization tasks. Thus, gasification plays a significant role in bioenergy policy. (Zhou *et al.*, 2012) Also Zhang et al. see small-scale biomass gasification as a feasible option for energy production in the east, northeast, central and central-south China, where lignocellulosic biomass is abundant. (Zhang *et al.*, 2013)

Biomass power is trending in India as a means to power the rural areas of the country. Over 600,000 villages in India could utilize power from biomass. The target is to increase the biomass power generation by 4,300 MW. Installed biomass power capacity reached 3600 MW in March 2013 and the potential biomass power potential exceeds 17,000 MW, calculated by the available feedstock. Approximately 155,000 rural-industrial biomass gasifiers are already in operation. (Kumar *et al.*, 2015)

In Canada, the current feed-in tariff would be adequate for small-scale gasification CHP, if the plant operates without continuous presence of an operating engineer. The cost of harvesting residues, as well as their pretreatment and transportation is low for small-scale gasification. The main costs arise from gasification infrastructure costs as well as operation and maintenance costs. (Cleary, Wolf and Caspersen, 2015)

In Brazil, small-scale biomass gasification features as an alternative for rural off-grid electricity generation option. Biomass plays a major role in renewable energy. Available feedstocks include agricultural and wood-processing residues. Now the main source of renewable energy are sugarcane products. (Chaves *et al.*, 2016)

Buchholz et al. found that in Uganda, social criteria affect the viability of bioelectricity more than the costs. The social criteria include low training needs, high employment rate, certainty of business schemes and low planning and monitoring needs. Also ecological criteria, such as reduced competition for land and reduced pollution affect the decisions. (Buchholz *et al.*, 2009)

To conclude, the drivers for small-scale gasification CHP are the distributed energy trend, climate change mitigation and local employment. Sustainability relies on voluntary actions. (REN21, 2015) The impacts of biomass gasification CHP include GHG emissions reduction, land-use change and health impacts as well as changes in biodiversity, soil fertility, water use and water quality. (Eisentraut and Brown, 2012)

2.4.2 Existing plants and manufacturers

The bioenergy industry is composed of feedstock suppliers and processors, delivery and equipment manufacturers, for both biomass handling and conversion. (REN21, 2015) This chapter introduces the equipment manufacturers of gasifier CHP plants and product gas motors. Additionally, some existing plants are presented.

Downdraft gasification technology dominates the small-scale combined heat and power production. Lists of manufacturers date quickly, as the market changes rapidly. Small companies are overtaken and new manufacturers enter the market. Gasifiers do not belong to the core businesses for most suppliers. (Kirkels and Verbong, 2011)

A Finnish small-scale gasifier company Volter produces CHP units for households. The unit generates 40 kW of electricity and 100 kW of hot water. Figure 24 presents the schematic of the gasifier unit. (Volter Oy, 2016b) Another company producing small-scale gasification CHP equipment is called Spanner. The power range of the offered Spanner Re^2 plants ranges from 19 to 270 kW$_e$. (Spanner Re^2 GmbH, 2016)

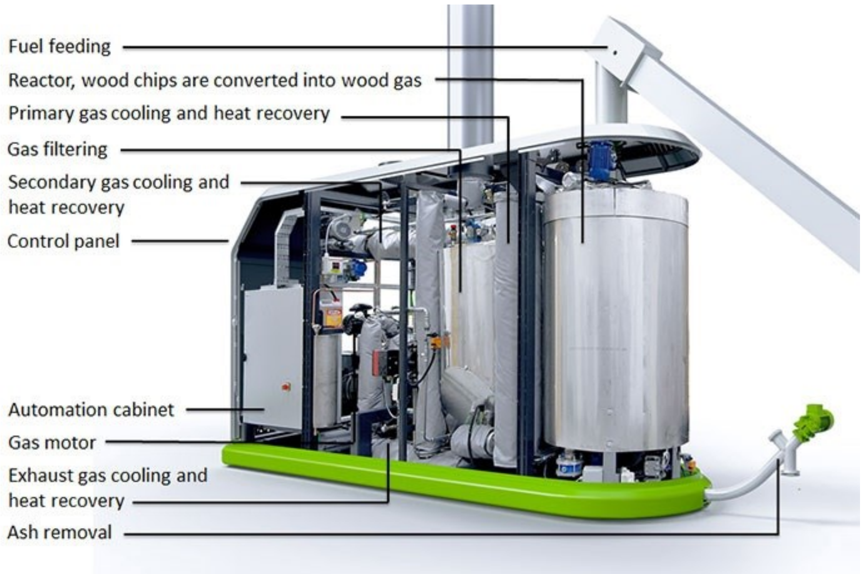


Figure 24. Volter gasification CHP unit. (Volter Oy, 2016a)

Biomass gasifiers have been installed especially in Europe. At least 30 plants of 100…2000 kW$_e$ could be identified. According to IEA Bioenergy Task 33 status report, there are five gasification facilities under construction in the participating countries. Small-scale facilities include Rheinfelden, Arnsberg-Wildhausen and Pfalzfeld. The listing is incomprehensive, as Burkhardt alone has built over 100 gasifiers. In 2015, six commercial gasifier CHP plants started operation. Wood chips dominate as the feedstock for existing plants. (Hrbek, 2016)

Skive, Güssing and Harboore biomass gasification plants stand as remarkable pilot plants, although they exceed the small-scale CHP plants category. The Güssing 8 MW$_{th}$ plant utilizes dual fluidized bed technology. The Skive 20 MW$_{th}$ bubbling fluidized bed gasification plant has operated 7500 hours per year. Harboore 20 MW$_{th}$ plant has reached 8000 h/y operation. (Hrbek, 2016; Molino, Chianese and Musmarra, 2016)

BTG biomass technology group has consulted CHP gasifier projects in Tanzania, Sri Lanka, Indonesia, Brazil, Ivory Coast, Seychelles, Fiji, Solomon Islands, Vanuatu, Uruguay, Paraguay, and Ecuador. Additionally, projects have been implemented in

Indonesia, Papua New Guinea, Western Samoa, Nicaragua, Guatemala, Thailand and Ghana. (Brandin et al. 2011, p.111-113)

In Japan, local projects for biomass utilization proceed and over 10 biomass gasification CHP demonstration plants of 50…300 kW_e have been built (Yagi and Nakata, 2011) with fixed bed, fluidised bed and rotary kiln designs. Japanese gasifier manufacturers include Chugai Ro, Tsukishima Kikai, JFE Engineering Corporation, Kawasaki Heavy Industries, Torisumi and Satake. (Morita and Ogi, 2012) A few small-scale gasification plant projects have been demonstrated in the USA. (Roos, 2010, pp. 42–44)

In China, Hefei Tianyan Green Energy Development (Tianyan) and Guangzhou Institute of Energy Conversion have demonstrated biomass gasification and power generation (Zhou *et al.*, 2012). One CHP downdraft gasifier based application utilises agricultural residues as a feedstock in Jilin. (Zhang *et al.*, 2013)

Jenbacher has documented existing engines running on product gas. Other engine manufacturers include Cummins, Caterpillar, Lovol, MTU, Perkins, Deutz, MWM, Waukesha, Kubota, Yanmar, Isuzu, Daewoo, Hyundai and Mitsubishi. In developing countries, converted diesel and natural gas gensets run on product gas. In China Cummins-India and Weichai provide engines for biomass gasification. In the Nordic countries, Volvo, Scania, Wärtsilä and MAN provide engines. (Brandin et al. 2011, p.72-73)

2.4.3 Support mechanisms

The EU 2020 targets are applied by the National Renewable Energy Action Plan (NREAP), which is required by Directive 2009/28/EC on the Promotion of Electricity Produced from Renewable Energy Sources. Table 4 summarizes the targets for Germany, Austria, UK and Finland.

Table 4. EU 2020 targets for Germany, Austria, UK and Finland. (OECD/IEA, 2016)

NREAP target for 2020	*Germany*	*Austria*	*UK*	*Finland*
RES-% of primary energy consumption	18	34	15	38
RES-% of heating and cooling	15.5	33	12	47
RES-% of electricity	37	71	31	33
RES-% of transport	13	11.5	10	20

Japan promotes renewable energy introduction to energy markets. The long-term Energy Supply and Demand Outlook based on Strategic Energy Plan (2014) defines a target for 22…24 % renewable electricity generation in 2030. Biomass contributes to 3.7 to 4.6 %. The outlook is re-examined every three years. Cogeneration and energy efficiency are highly valued. Energy policy aims mainly to reduce dependency on imported fossil fuels. Consequently, Japan has set feed-in tariffs for electricity generated from renewable sources. (Morita and Ogi, 2012) Biomass power plants under 2 MW receive 13…40 JPY/kWh for 20 years, which corresponds to 297.81…238.25 €/MWh. (OECD/IEA, 2016)

Germany has an ambitious renewable energy policy, which comprises both international and national policies. Germany participates in the EU emissions trading system (ETS). Renewable energy policy framework involves the Energy Concept, which states the future milestones for GHG emissions reduction, renewable energy supply (RES) share of energy, primary energy consumption reduction and building renovation and energy performance upgrade. In addition to renewable energy subsidies, Germany phases out nuclear. The Energy Concept and nuclear phase-out form the 'Energiewende'. (Knaut *et al.*, 2016) (OECD/IEA, 2016)

German targets are also stated in the 2014 Amendment of the Renewable Energy Sources Act, which introduces the annual biomass electricity installation target of 100 MW. This is accomplished by offering market premiums for over 500 kW plants and feed-in tariffs for smaller plants. Market premiums require direct marketing. Renewable Energies Heat Act stipulates certain buildings to cover part of their heating and cooling with renewable energy. Additionally, a biofuels quota is established. (OECD/IEA, 2016) However, Knaut et al. state that the existing policies, overlapping with EU ETS, dissatisfy the GHG emission reduction targets (Knaut *et al.*, 2016).

Energy Policy in Austria emphasizes support for biomass CHP. The Green Electricity Act in 2012 aims to the installation of 200 MW bioenergy until 2020, including biogas. The feed-in tariff of Ökostromverordnung (ÖSVO) for solid biomass amounts to 149.80 €/MWh for 15 years. An additional 20 €/MWh is granted for efficient cogeneration. Additionally, a Combined Heat and Power Law provided investment subsidies between 2009 and 2012. Existing plants collect subsidies for each produced MWh. A climate protection law also holds. (OECD/IEA, 2016)

The UK has recently introduced a package called Electricity Market Reform, which consists of four main measures: Contracts-for-Difference, capacity auctions, Emission Performance Standard and Carbon Price Floor. Contracts-for-Difference replaces Renewable Obligations in 2017. The RES electricity generators receive at least a strike price for 15 years. The Carbon Price Floor, £15.7/tCO_2 in 2013, will be increased to £30/tCO_2 by 2020. (OECD/IEA, 2016) These correspond to 21.63…41.33 €/tCO_2.

Older UK policies include the Renewable Heat Incentive and feed-in tariffs for renewable electricity. Renewable Heat Incentive RHI supports renewable heat installations 20 years by fixed payment. For biomass, the tariff depends on the size of the plant. Biomass heat tariff ranges from 1.17 to 5.18 p/kW_{th} or 16.12…71.37 €/MWh. Solid biomass CHP commissioned after December 2013 receive 4.17 p/kW_{th} or 57.45 €/MWh. However, the feed-in tariffs for renewable electricity exclude biomass gasification plants. (OECD/IEA, 2016)

In Finland, the measures taken to achieve EU 2020 targets include feed-in tariff, long term strategy, biofuels promotion, promotion of energy from woodchips, buildings RES and energy efficiency requirements. (OECD/IEA, 2016) The relevant policies for biomass gasification are feed-in tariff for wood fuels and investment aid. Finland is preparing a new energy and climate strategy.

The Energy Aid Scheme grants 30 % support for renewable energy investments, new technology can increase the share to 40 %. This supports mainly large-scale energy producers, since the detailed requirements in the legislation. Additionally, research and development receives funding. Support for heat production incorporates a heat bonus of 20 €/MWh for plants utilizing wood and farmers' subsidy for renewable energy heat plants. (Ruggiero, Varho and Rikkonen, 2015)

New timber chip and wood fuel power plants receive a feed-in tariff, with the maximum electricity price of 103.50 €/MWh for small scale CHP installations, if the plant has refused state support for the investment and fulfils other conditions of the tariff (Energy Authority, 2016).

2.4.4 Economic factors

The economic factors influencing biomass gasification consist of energy prices, energy consumption, economic development, interest rates, inflation, technology prices and market organizations. CHP costs consist of feedstock, technology and operational costs.

Table 5. Energy prices in Austria, Finland, Germany, Japan and UK. (OECD/IEA, 2015, pp. 42–43)

	Austria	*Finland*	*Germany*	*Japan*	*UK*
Elecricity: industry, €/MWh	121.78	94.20	161.56	169.55	141.72
Electricity: households, €/MWh	240.59	181.48	356.06	228.26	230.43
Natural gas: industry, €/MWh	40.84	41.26	40.21		36.11
LFO: households, €/1000 liters	739.19	878.17	613.27	641.47	653.62
HFO, €/t	364.00		288.42	538.47	

Table 5 compares the energy prices and energy consumption of Austria, Finland, Germany, Japan and the UK. The electricity prices in Finland are significantly lower than central Europe. Electricity price for industry in Japan exceeds the others. The total primary energy supply divided by gross domestic product is similar in all of the countries. (OECD/IEA, 2015)

Table 6. OECD electricity prices in 2014. (OECD/IEA, 2015)

Electricity prices OECD	*Min, €/MWh*	*Max, €/MWh*
Industry	49.21	295.43
Households	81.19	356.06

Table 6 shows the price ranges of electricity. Electricity prices in 2014 for industry and household vary between the OECD countries. The prices for industry range from 49.21 €/MWh in Norway to 295.43 €/MWh in Italy. Household electricity prices vary between 81.19 €/MWh in Mexico and 356.06 €/MWh in Germany. (OECD/IEA, 2015, p. 43) The average exchange rates used in the unit conversion are presented in Table 12 on page 59 (Bank of Finland, 2015).

Table 7. Feedstock cost in the EU including transport costs. (IRENA, 2012, p. 30)

Feedstock	*Price, €/MWh*
Woodchips from local energy crops	16.9…26.6
Woodchips from Scandinavian forest residues to continental Europe	27.9…32.8
Local agricultural residues	15.6…19.5
Imported pellets from US to continental Europe	30.2…35.0

Most of the biomass is traded locally, although international trade on wood pellets and wood chips is rising. (IRENA, 2012) The price of biomass consists of material, collection, transportation and pretreatment costs. The transportation costs are significant in the biomass feedstock cost. Biomass costs in different regions vary significantly. (Asadullah, 2014a) Table 7 presents the biomass prices in the EU. The price of local agricultural and woodchips is lower than that of imported woodchips or pellets.

The fuel price in heat production varied between 15 and 40 €/MWh in 2016 without value-added tax, as seen in Figure 25. Consumer prices of heat varied between 58 and 81 €/MWh, if electrical heating is excluded. (Official Statistics of Finland, 2016) Pöyry has compiled statistics of the prices of fuels for heat production in Finland. The price of light fuel oil has fluctuated 45…95 €/MWh while heavy fuel oil prices have ranged 35…70 €/MWh in the last ten years. (Pöyry, 2016)

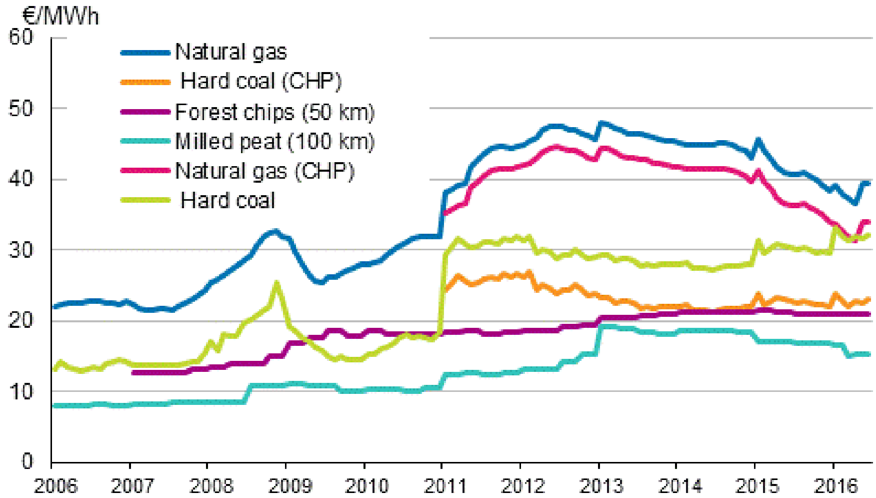


Figure 25. Fuel prices in heat production without value added tax. (Official Statistics of Finland, 2016)

Operation and maintenance costs can be divided into fixed and variable component. The operation and maintenance cost of gasification CHP varies from one technology to another significantly. The fixed operation and maintenance cost accounts for 3…6 % of the total investment (Brammer and Bridgewater, 2002; IRENA, 2012). Danish Energy Agency even presents estimates of only 2 % fixed component for a staged downdraft gasifier CHP. For an updraft gasifier the fixed cost accounts for 5 % of the investment. (Danish Energy Agency and Energinet.dk, 2012)

The variable operation and maintenance cost of an updraft gasifier CHP plant totals 19 €/MWh in 2015. For a CHP staged downdraft gasifier plant of 1…10 MW the variable operation and maintenance cost amounts to 18 €/MWh in 2015, but the variable cost decreases to 17 €/MWh after 2020. The variable operation and maintenance costs include consumption of auxiliary materials (water, lubricants, fuel additives), treatment and disposal of residuals, output related repair and maintenance, spare parts and own electricity consumption. Fuel costs are excluded. (Danish Energy Agency and Energinet.dk, 2012)

Several sources estimate the capital costs for gasification CHP with engine. Table 8 compiles the specific investment costs. They are converted to the year 2015 using chemical engineering plant cost index (CEPCI) and the European Central Bank exchange rates convert the sums to euros. The cost of a plant in year 2015 is obtained as in equation (37) on page 59 (Mignard, 2014).

Table 8. Specific investment cost estimates found in literature.

Source	*Size, kW_e*	*Specific investment cost, €/kW_e*
IRENA 2012	all	5100-6000
REN21 2015	30-40000	1800-5000
Faaij 2006	100-1000	1100-3300
Danish Energy Agency 2012	1000-20000	2000-3400

According to the Danish Energy Agency, the specific investment for a 1.4 MW CHP updraft gasifier plant in 2015 equals 3700 €/kW. A staged downdraft gasifier CHP plant of 1…10 MW the specific investment costs range 3400…3700 €/kW in 2015, but decrease to 2400…3000 €/kW by 2030. (Danish Energy Agency and Energinet.dk, 2012) The specific investment for gasification CHP estimated by IRENA exceeds the costs stated by the others. REN21 investment costs stretch widely due to the extensive size variation.

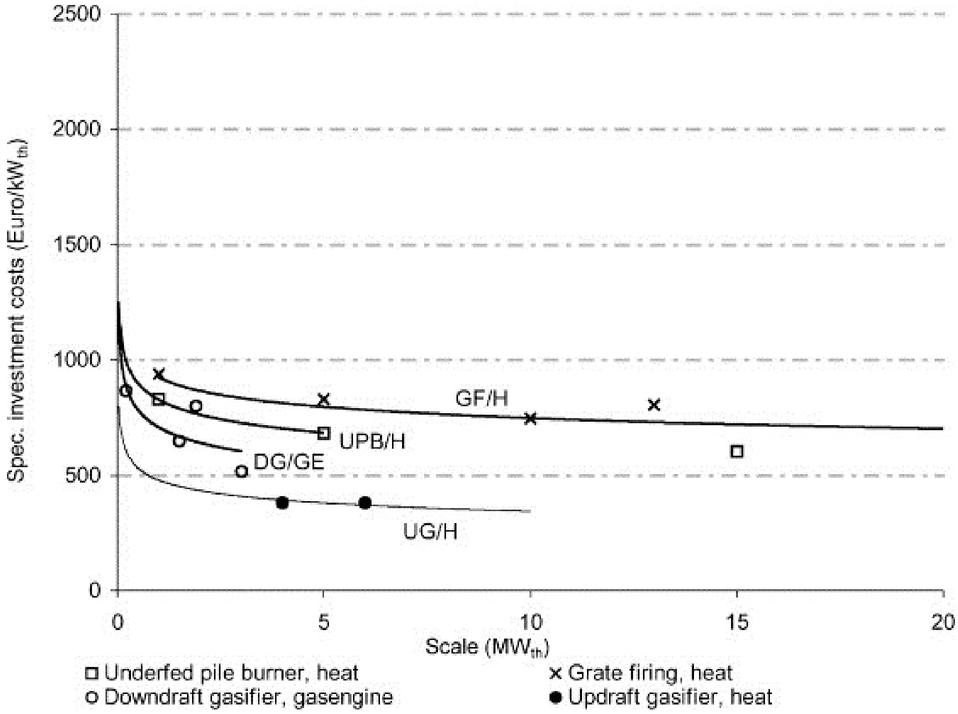


Figure 26. Specific investment of CHP production in 1999 euros as a function of plant thermal size. (Dornburg and Faaij, 2001)

Faaij presents much lower estimates (Figure 26). Gasification CHP plants with 100…1000 kW gas engine cost 1110…3300 €/kW depending on the configuration (Faaij, 2006, p. 349). Figure 26 presents the 1999 investment costs for downdraft gasifier and gas engine, as well as updraft gasifiers for heat-only production. (Dornburg and Faaij, 2001) The investment costs converted to 2015 euros equal 1000…2600 €/kW_{th} for the DD and 570…1100 €/kW_{th} for the UD.

The Kokemäki demonstration plant with technology similar to Gasgen cost 4.5 M€. The plant produced 1.8 MW_e of electricity and 3.9 MW heat, which corresponds to 5.7 MW_{th} capacity. Thus, the specific investment of the plant is 2500 €/kW_e or 790 €/kW_{th}. Chapter 3.3.6 presents the costs converted into 2015 currency.

3 Techno-economic analysis

3.1 Selection of methods

The feasibility of the VTT Gasgen gasifier is evaluated by techno-economic calculations. Mass and energy balances are calculated in Excel (Kurkela, 2016). Additionally, economic indicators are calculated and their sensitivity analysis is performed in Excel. Chapter 3.3 starting on page 49 presents the mass and energy balance calculations.

Chapter 3.3.6 describes the feasibility calculations. The feasibility is evaluated by annual profit, net present value (NPV) and payback period (PBP). Sensitivity analysis is conducted by varying electricity, heat, steam and feedstock prices. Chapter 3.3.7 describes the sensitivity analysis in more detail. The results are compared to the present and future market conditions.

The feasibility is analysed in three case studies:

1. District heating CHP plant with engine and boiler
    a. Savon Voima
    b. Small district heating CHP plant
    c. Kiteen Lämpö
2. Industrial steam CHP plant with engine and boiler
    a. Raute
3. Steam plant (replacing fuel oil or natural gas with product gas)
    a. Turku Energia

The case studies have been selected from the companies participating in the Gasgen project. Figure 27 illustrates the different cases. Chapter 3.2 describes the cases in detail. Chapter 3.2.1 presents the process diagrams. Appendix 1 presents the initial values of the energy balance calculations. Table 14 in chapter 3.3.6 compares all the initial values of the feasibility calculations.

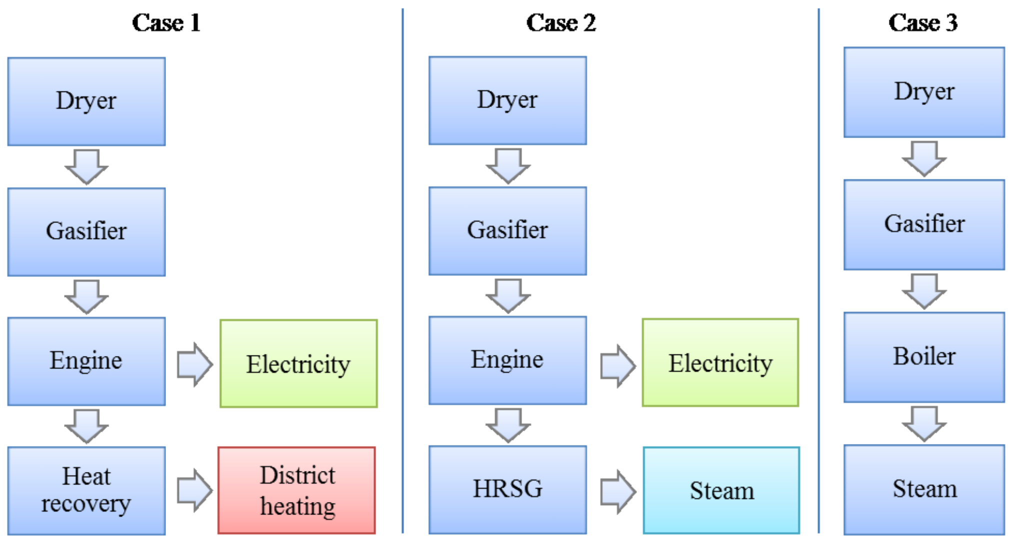


Figure 27. Case studies of the Gasgen gasifier applications.

3.2 Case descriptions

3.2.1 Process diagrams

The process includes feedstock crushing and drying, feedstock feeding, the Gasgen gasifier, gas cooling and cleaning, heat recovery, an engine and a generator as well as the ash disposal. In Case 1, the process produces electricity and district heating. Heat recovered from the gas cleaning and cooling, as well as engine cooling is utilized in drying the biomass to 15 % moisture content. The engine utilizes also landfill gas in case 1c. Hot product gas and flue gas provide the hot water for district heating.

In case 2, the process includes feedstock crushing and drying, the Gasgen gasifier, gas cooling and cleaning, engine and a heat recovery steam generator (HRSG). The energy of the feedstock transforms into electricity and steam. Heat from the gas cleaning and engine cooling dries the feedstock to 15 % moisture content. The boiler produces 18 bar 206 °C saturated steam. The HRSG utilizes heat from the hot product gas and the flue gas. The boiler efficiency for steam production is obtained by calculating the losses. The cogeneration system contains no steam turbine.

In case 3, no electricity is produced. A conventional oil or gas-fired boiler replaces the engine, generator and heat recovery. The plant converts the energy from the feedstock into steam. Heat for drying the feedstock to 30 % moisture content is derived from the flue gas scrubber. The boiler efficiency is obtained by calculating the losses. Figure 28 compares the process diagrams of the three cases.

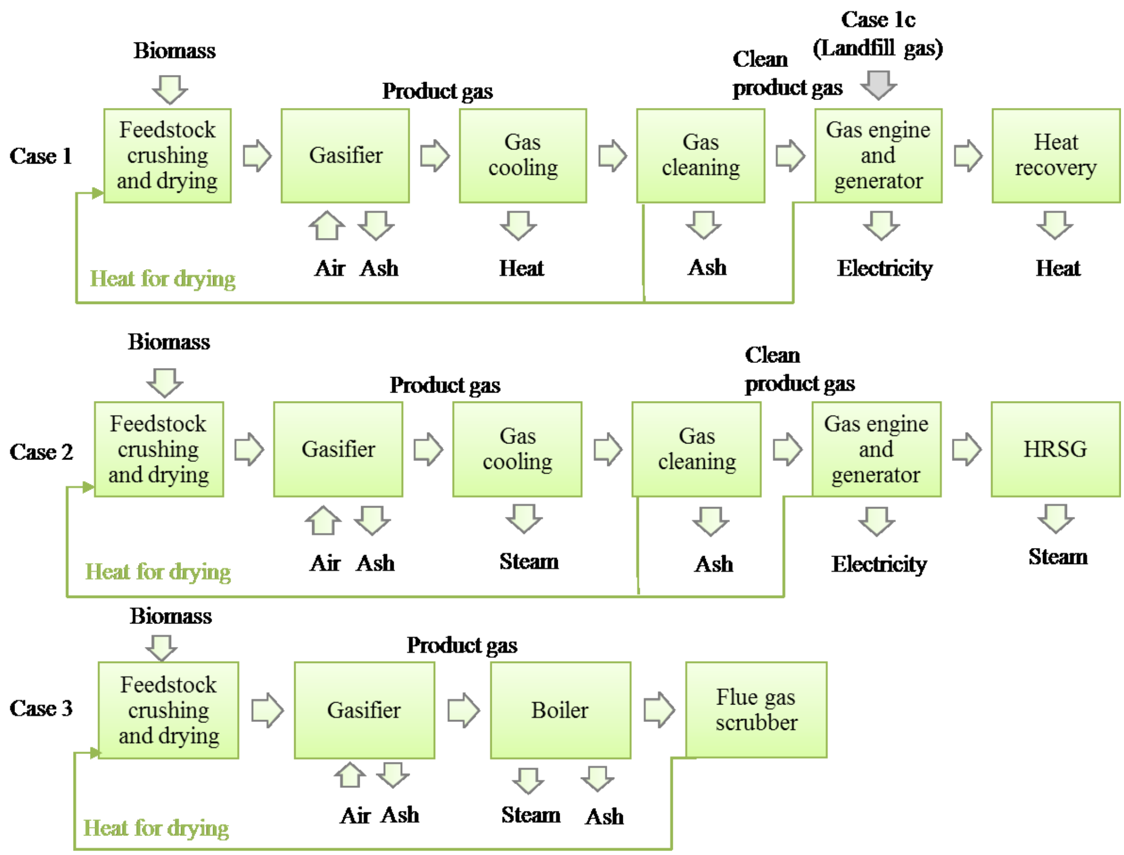


Figure 28. Process diagrams of the three cases.

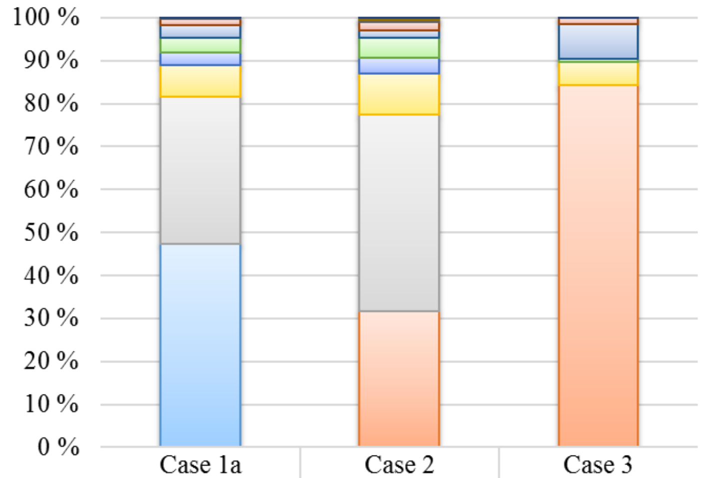
3.2.2 Energy balances

Figure 29 compares the energy allocation in the three cases. The output energy represents 100 %. Input energy includes feedstock energy as well as the energy of the gasification and combustion air. Appendix 1 presents the initial values of the energy balance calculations and Table 14 on page 62 presents the electrical and thermal efficiencies derived from the calculations.

Most of the energy in the feedstock produces district heating and electricity in case 1a. The main losses include drying, unburnt carbon in the gasifier, losses in the heat recovery from product gas, losses in the gas cleaning, CO-loss and heat loss in the engine, as well as enthalpy of the flue gas after heat recovery. Part of the electricity is consumed as internal load.

The energy of the feedstock is converted into electricity and steam in case 2. The main losses occur in the dryer, gasifier and the engine. Small amount of the energy is lost in the scrubber between the gasifier and HRSG. Part of the electricity is consumed as internal load.

In case 3, the energy of the feedstock transfers into steam. Losses occur in the dryer, boiler (radiation and CO losses), gasifier (unburned carbon) and the flue gas scrubber. The complete combustion of the boiler results in smaller CO-losses than the engine. The gasifier losses increase compared to cases 1a and 2, since the biomass is only dried to 30 % moisture content. On the other hand, the dryer losses in case 3 decrease simultaneously. The flue gas losses in case 3 are minimal, as the flue gas scrubber recovers the heat efficiently.



	Case 1a	Case 2	Case 3
Scrubber losses	0.04 %	0.06 %	0.09 %
Product gas boiler losses	0.06 %	0.57 %	0.00 %
CO losses	0.25 %	0.33 %	0.00 %
Engine/boiler heat losses	1.48 %	1.94 %	1.28 %
Gasifier losses	2.76 %	1.66 %	8.19 %
Flue gas losses	3.61 %	4.76 %	0.82 %
Internal load	2.76 %	3.64 %	0.00 %
Dryer losses	7.33 %	9.66 %	5.41 %
Electricity	34.45 %	45.60 %	0.00 %
Steam	0.00 %	31.77 %	84.20 %
District heating	47.26 %	0.00 %	0.00 %

Figure 29. Energy allocation in the three cases.

3.2.3 Case 1a: Savon Voima

In case 1a, the Gasgen gasifier is applied at district heating CHP production at Savon Voima. The plant produces heat and electricity. The interesting plant size varies between 5…10 MW district heat production. Two plants at both ends of the spectrum depict this range. The feedstock consists of industrial byproducts such as sawmill residues. Bark and saw dust cost on average 16 €/MWh (Sahateollisuus ry, 2016). The electricity price, 30 €/MWh, corresponds to the current market price levels.

The alternative cost of heat production represents the heat price. Thus, the feasibility calculations take into account the alternative option: heat-only production by a biomass boiler. Equation (1) presents the alternative heat cost calculation.

$$s = \frac{\Phi h(O_v + O_f) + \dfrac{\Phi h f}{\eta_{boiler}} + EAC}{\Phi h} \tag{1}$$

where s is the heat price [€/MWh]
Φ is the district heating or steam power [MW]
h is the full load hours [h]
O_v+O_f is the operation and maintenance cost [€/MWh]
f is the fuel price [€/MWh]
η_{boiler} is the boiler efficiency [-]
EAC is the equivalent annual cost [€]

Equation (45) on page 61 presents the calculation of EAC. Table 9 shows the initial values of the alternative heat cost calculation. The operation and maintenance cost for a biomass district heating plant equals 5.4 €/MWh (Danish Energy Agency and Energinet.dk, 2012). Thus, equation (1) wields 30.95 and 29.90 €/MWh as the alternative cost of heat production at the 5 and 10 MW_{DH} plants.

Table 9. Initial values of the alternative cost of heat production.

Full load hours	8000 h
Feedstock cost	16 €/MWh
Operation and maintenance cost	5.4 €/MWh
Boiler efficiency	0.85
Specific investment cost	0.75 M€/MW
Interest rate	8 %
Investment lifetime	20 years

3.2.4 Case 1b: Small district heating CHP plant

In case 1b, the Gasgen gasifier is also applied in district heating CHP. Adapted for a small town, the plant produces 1 MW heat. The feedstock consists of wood chips at the cost of 22 €/MWh. The heat price for the customer is 64 €/MWh without tax. The electricity is sold at 30 €/MWh market price. The lifetime of the investment is 20 years and the interest rate is 5 %.

3.2.5 Case 1c: Kiteen Lämpö

The Gasgen gasifier is applied at district heating CHP in case 1c. Kiteen Lämpö produces district heating and electricity. An existing 160 kW_e gas engine produces heat and power from the landfill gas. The landfill gas production decreases steadily. The present production is 20 m^3/h CH_4 and it will cease in approximately 10 years. The existing engine and diminishing landfill gas production call for a new fuel for the engine. Thus, the engine runs on both product gas and landfill gas simultaneously.

The landfill gas utilized at Kiteen Lämpö contains approximately 50 vol-% CH_4 and 50 vol-% CO_2. The energy content of the landfill gas is calculated in equations (2) to (7). The utilization rate of the plant is 95 %. Thus, the full load hours are 8322 hours.

The molar mass of the gas is

$$M_{LFG} = \phi_{CO_2} M_{CO_2} + \phi_{CH_4} M_{CH_4} \tag{2}$$

where M_{LFG} is the molar mass of the landfill gas [kg/kmol]
ϕ_i is the volume fraction of the component [-]
M_i is the molar mass of the component [kg/kmol]

Table 10 lists the molar masses and heating values of the gas components. As the molar volume of ideal gas equals 22.41 dm^3/mol, the molar flow of the gas components can be calculated.

$$\dot{n} = \frac{\dot{V}}{1000 V_m} \tag{3}$$

where $\dot{n}$ is the molar flow of the gas component [mol/s]
$\dot{V}$ is the volume flow of the gas component [m^3/s]
V_m is the molar volume of ideal gas [dm^3/mol]

Mass flow of the gas

$$\dot{m} = \dot{n} M_{LFG} \tag{4}$$

Mass fractions of the gas

$$w_i = \frac{\phi_i M_i}{\sum M_i} \tag{5}$$

where w is the mass fraction of the component [-]

Thus, the mass flows of the gas components

$$\dot{m}_i = w_i \dot{m} \tag{6}$$

The energy content of the landfill gas

$$\Phi_{LFG} = \dot{m}_{CH_4} H_{CH_4} \tag{7}$$

where H_{CH_4} is the heating value of methane [MJ/kg].

The energy content of the landfill gas with 160 kW_e electricity production equals 89 m^3/h. Thus, the volume flow amounts to 15 m^3/h, which corresponds to the decreasing landfill gas production. The cost of the landfill gas is 30 €/MWh.

3.2.6 Case 2: Raute

The Gasgen gasifier is applied at industrial CHP in case 2. The case study is conducted with Raute, a company supplying plywood and LVL (Laminated Veneer Lumber) mill equipment and services. The new biomass gasifier CHP plant is included in the mill equipment, replacing grate boilers in the steam and electricity production. The wood product mills require electricity and 18 bar saturated steam for the production. The mill produces 8 MW steam in this case.

The plywood raw materials consist of spruce and birch wood. The bark, wood chips, plywood edges and grinding dust are available as the side product of the mill at the expense of 20 €/MWh.

The fuel power of the plant exceeds 20 MW, which requires two gasifiers. The gasifiers use separate feeding systems, but common scrubber and the plant incorporates one boiler and one engine. The estimated investment cost share of the gasifier and feeding system is half of the investment cost without the engine. Equation (38) on page 59 presents the investment cost calculation for the engine. By modifying the equation, the investment cost of the plant with two gasifiers, I_2,

$$I_2 = \frac{1}{2} I_1 \frac{\Phi_2}{\Phi_1}^y + I_1 \frac{0.5\Phi_2}{\Phi_1}^y + I_{engine} \tag{8}$$

where I_1 is the investment cost of the reference plant without the engine [€]
I_{engine} is the investment cost of the engine scaled to the 8 MW plant [€]
Φ_i is the output energy of the plant [MW]
y is the scaling factor [-]

3.2.7 Case 3: Turku Energia

In case 3, Turku Energia produces steam for industrial customers. Turku Energia has already invested in wood gasification at the Artukainen steam plant (Haaksi, 2015). Thus, gasification is a familiar technology for Turku Energia.

Case 3 studies Gasgen gasifier replacing fuel oil. The product gas replaces the fuel oil in a 750 kW steam boiler. This case allows the comparison of CHP and steam-only generation. As the investment does not include engine or generator, the investment cost is lower than in case 2. The variable operation and maintenance costs also decrease without the engine.

Moreover, steam is valued higher than district heating, which contributes to the feasibility compared to case 1. The steam produced is valued at 70 €/MWh and the feedstock is wood chips, at the expense of 20 €/MWh.

3.3 Calculations

3.3.1 Dryer

Figure 30 presents the mass and energy balances of the dryer. Drying medium and feedstock flow through the dryer, where part of the moisture in the feedstock transfers into the drying medium. The energy in the heat brought to the dryer heats the feedstock and water resulting in the water transferring to the drying medium. The heat not absorbed by the feedstock is lost.

The upper balance in Figure 30 represents cases 1 and 2, where the feedstock is dried to 15 % moisture content (MC), as the lower moisture content increases the electrical efficiency of the engine. The lower balance is applied in case 3, where the product gas is fired directly in a boiler to produce steam. Moisture content of the feedstock equals 30 %. The dryer efficiency is 60 %. (Kurkela, 2016) Appendix 1 presents the initial values of the energy balance calculations.

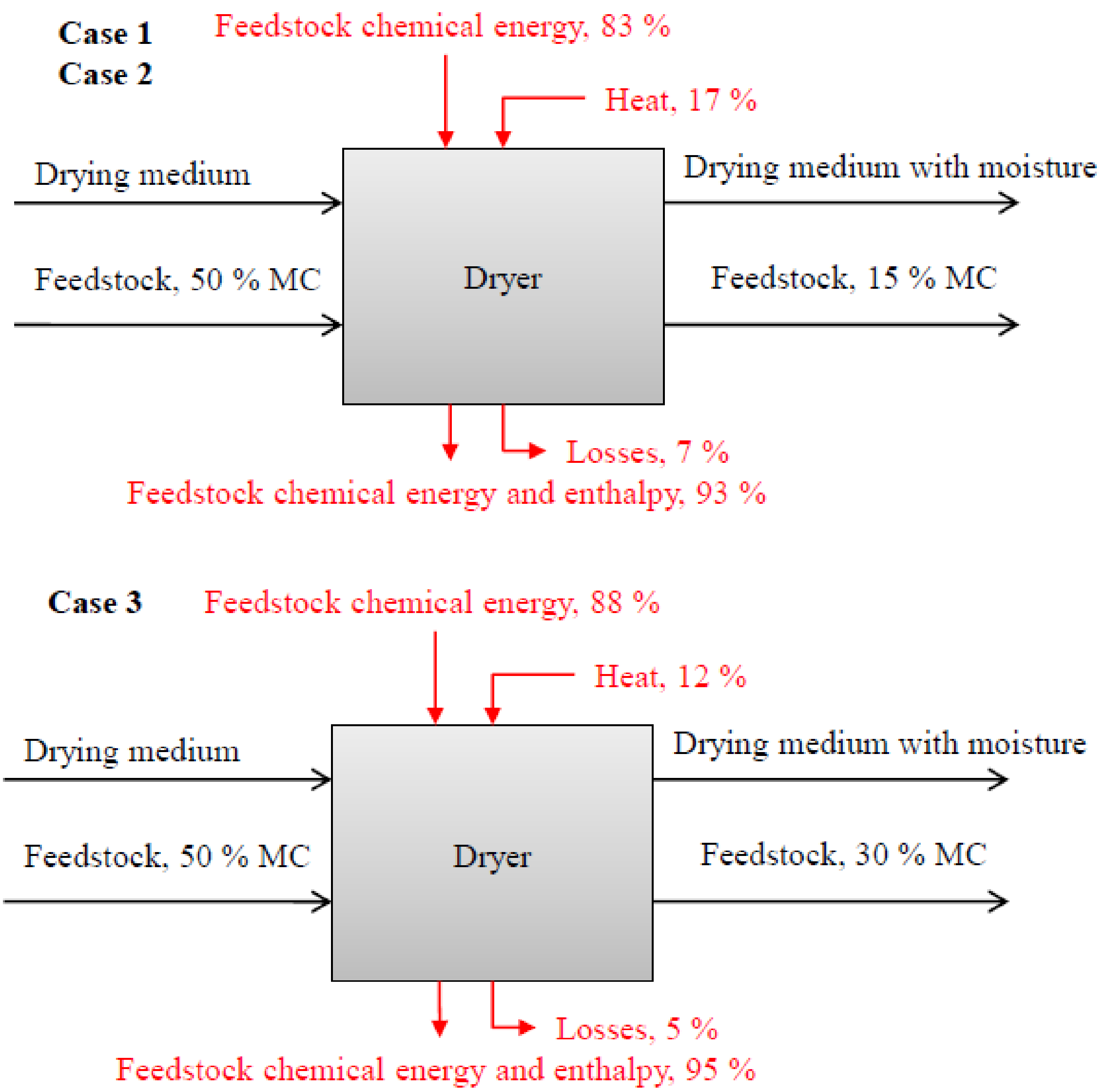


Figure 30. Mass balance of dryer in black and energy balance of the dryer in red.

Equations (9) to (15) present the calculations of the dryer.

$$LHV_1 = (1 - x_1)LHV_d - 0.02441x_1 \tag{9}$$

$$LHV_2 = (1 - x_2)LHV_d - 0.02441x_2 \tag{10}$$

where LHV_1 is the LHV before drying [kg/s]
LHV_2 the LHV after drying [kg/s]
LHV_d is the lower heating value of dry fuel [kg/s]
x_1 is the moisture content before drying [-]
x_2 is the moisture content after drying [-]

Mass flow of the fuel before drying is obtained in equation (11).

$$\dot{m}_1 = \frac{\Phi_{f1}}{LHV_1} \tag{11}$$

where $\dot{m}_1$ is the mass flow of the fuel before drying [kg/s]
Φ_{f1} is the fuel power before drying [MW]

Mass flow of fuel after drying is obtained by calculating the mass flow of the dry fuel.

$$\dot{m}_d = \dot{m}_1(1 - x_1) \tag{12}$$
$$\dot{m}_2 = \dot{m}_d(1 - x_2) \tag{13}$$

where $\dot{m}_d$ is the mass flow of the dry fuel [kg/s]
$\dot{m}_2$ is the mass flow of the fuel after drying [kg/s]

Fuel power after drying

$$\Phi_{f2} = \dot{m}_2 LHV_2 \tag{14}$$

Actual drying heat input

$$\Phi_{drying} = \eta_{drying}(\Phi_{f1} - \Phi_{f2}) \tag{15}$$

where Φ_{drying} is the heat required for the drying [MW]
η_{drying} is the dryer efficiency [-]

3.3.2 Gasifier

The feedstock of the gasifier CHP plant has a wide variety from wood chips, bamboo and eucalyptus to agrofuels. The chemical composition of the feedstock is tabulated including carbon, hydrogen, nitrogen, oxygens, chlorine, ash, LHV (db) and moisture content before drying. The values for logging residue chips, plywood edges, bark, sawdust, reed canary grass and straw are obtained from Alakangas et al. (Alakangas *et al.*, 2016). The values for exotic wood species are presented for eucalyptus (Lenis, Osorio and Pérez, 2013) and bamboo (Zheng *et al.*, 2016). Table 2 on page 28 presents the feedstock compositions of these fuels. Only the values for logging residue chips are used in the mass balance calculations of this thesis.

Mass and energy balances are calculated for 100 g/s of feedstock (Kurkela, 2016). First, the nitrogen balance is calculated. Secondly, the hydrogen balance is calculated. Finally, carbon, oxygen, sulphur and ash are balanced by changing the product gas composition in order to minimize the calculation error for each element. Maximum error is 0.2 percent.

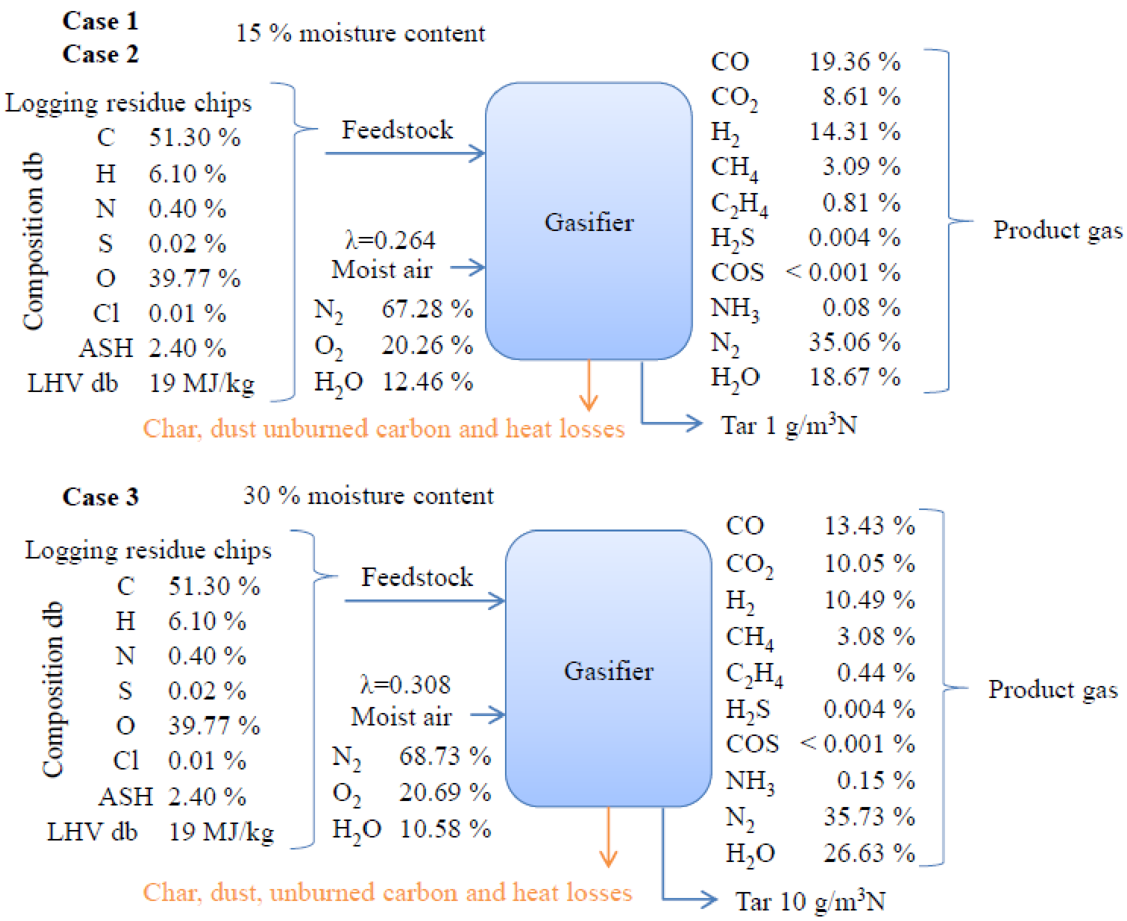


Figure 31. Mass balance of the gasifier. The feedstock composition is presented in mass percentage and the product gas composition in volumetric percentage.

Figure 31 displays the mass and energy balances of the gasifier. Logging residue chips and moist air are fed into the gasifier. Product gas, tar, char and dust exit. Feedstock chemical energy content transforms to product gas chemical energy and enthalpy, tar chemical energy and enthalpy, ash and dust energy, as well as unburned carbon and heat losses.

The mass fractions of the product gas components are calculated from the volume fractions.

$$w = \phi_{after} \frac{M_i}{\sum M_i} \tag{16}$$

where w is the mass percentage of the component [-]
M_i the molar mass of the component [kg/kmol]

The mass fractions enable calculation of the heating value of the product gas. Table 10 presents the molar masses and heating values of the product gas components. The lower heating value of the product gas is calculated for dry and wet gas. Thus, the chemical energy contained by the product gas is obtained, as the fuel power, energy of the unburnt carbon and heat losses are known.

Table 10. The molar masses (Perry and Green, 2007, table 2-179) and heating values (Yaws, 2012, tables 59-60) of the product gas components.

Component	*Molar mass, kg/kmol*	*Heating value, kJ/kg*
CO	28.010	10,103
CO_2	44.010	-
H_2	2.016	119,961
CH_4	16.043	50,034
C_2H_4	28.054	47,167
H_2S	34.080	15,204
COS	60.070	9,188
NH_3	17.031	18,604
N_2	28.013	-
H_2O	18.015	-

3.3.3 Engine and generator

The engine and generator produce electricity in cases 1 and 2. The engine calculations include electrical efficiency, mass and energy balance calculations. Appendix 1 presents the initial values of the energy balance calculations, including the engine electrical efficiencies of the cases.

The electrical power of the engine can be calculated if the energy content of the product gas and air, as well as engine electrical efficiency are known. Vukašinović et al. analysed the electrical efficiencies of almost six hundred ICE CHP units below 10 MW_e size. Equation (17) presents the engine electrical efficiency with natural gas, $\eta_{el,ng}$. (Vukašinović *et al.*, 2016)

$$\eta_{el,ng} = 25.64 P_{el}^{0.067} \tag{17}$$

where P_{el} is the nominal power of the engine [kW_e]

Equation (18) tells the engine efficiency for biogas, $\eta_{el,bg}$ (Vukašinović *et al.*, 2016).

$$\eta_{el,bg} = 30.31 P_{el}^{0.0424} \tag{18}$$

As biogas resembles the product gas more than natural gas, the equation for biogas serves as a base for the efficiency equation for product gas. As 38 % electrical efficiency is measured for a 1000 kW_e product gas engine (Herdin, 2014), and the biogas formula gives an efficiency of 40.62 % for a 1000 kW_e engine, the new formula for electrical efficiency of the engine fired with product gas, $\eta_{el,pg}$, is

$$\eta_{el,pg} = 30.31 P_{el}^{0.0424} - 2.62 \tag{19}$$

Figure 32 illustrates the mass balance and presents the volumetric percentages of the gas composition. Product gas and air enter the engine and flue gas exits. The gas composition describes the volumetric percentage of each component, when the feedstock of the gasifier is logging residue chips and the engine air factor is 1.5. Hydrogen burns completely, but some CO remains in the flue gases. Part of the nitrogen forms NO. The assumed quantity for the engine NO emission equals 0.01 %-vol.

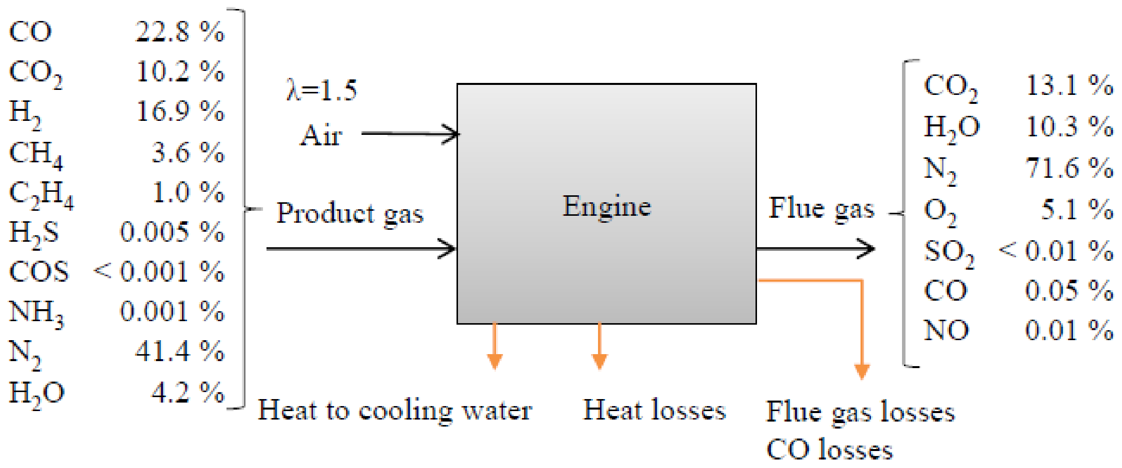


Figure 32. Mass and energy balance of the engine.

The energy in the product gas converts into electricity with the efficiency calculated earlier. The main losses include the CO-losses, heat losses in the engine and flue gas losses. The heat losses in the calculations are assumed 3 % of the gross heat output and the CO-loss is calculated in the programme with 500 ppm-vol CO in the flue gas (Kurkela, 2016). Internal load of the plant is assumed 3 %. Equation (36) on page 58 presents the calculation of the flue gas losses.

The energy balance in equation (20) yields the gross heat output of the engine.

$$\Phi_{engine} = \dot{h}_{air} + \dot{h}_{pg} + \Phi_{pg} - P_{el} - \dot{h}_{fg} - \Phi_{CO} \tag{20}$$

where Φ_{engine} is the engine gross heat output [MW]

$\dot{h}_{air}$ the enthalpy of the combustion air [MW]

$\dot{h}_{pg}$ the enthalpy of the product gas entering the engine [MW]

Φ_{pg} the product gas chemical energy [MW]

$\dot{h}_{fg}$ the flue gas losses [MW]

Φ_{CO} the CO loss [MW]

3.3.4 Heat recovery for drying

Heat is recovered from the product gas cleaning, engine cooling and flue gas scrubber. Figure 28 shows the energy flows to the drying in different cases. Firstly, heat recovery from engine cooling water is described. Secondly, the calculations of the product gas scrubber and the flue gas scrubber are presented.

The useful heat output of the engine divides between cooling water and flue gas. 17…26 percent of the fuel power of the engine is allocated to the cooling water in engines run with conventional fuels (Abedin *et al.*, 2013). 27 % of the fuel power heats the cooling water in a biogas-run engine (Yingjian *et al.*, 2014) and approximately 20 % in a natural gas engine (Gharehghani *et al.*, 2013). Thus, the heat allocated to the cooling water is assumed 27 % in the calculations, as biogas resembles the product gas the most. Heat recovery from engine cooling water is added to the mass and energy balance programme (Kurkela, 2016) as a part of this thesis.

Thus, the heat in the engine cooling water

$$\Phi_{cooling} = 0.27\Phi_{pg} \tag{21}$$

where $\Phi_{cooling}$ is the heat in the engine cooling water [MW]

Heat of the engine cooling is used for drying in case 2, as described in chapter 2.3.3. A boiler recovers the heat of the hot flue gas, which is described in chapter 3.3.5.

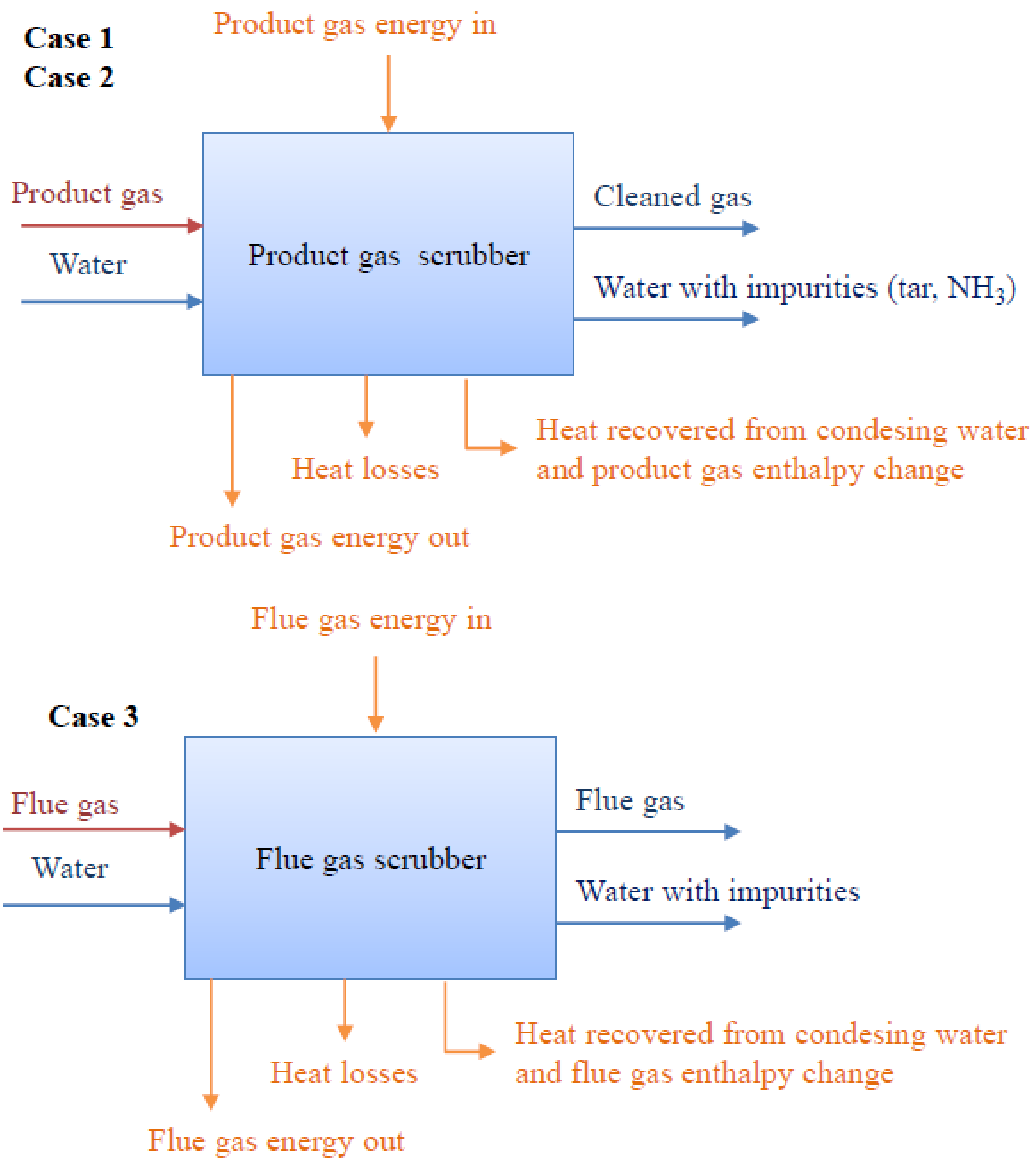


Figure 33. Flue gas scrubber energy (orange) and mass balance.

Scrubbers clean the product gas before the engine in cases 1 and 2 and the flue gas in case 3. The heat recovered from the scrubbers dries the biomass. Additionally, heat is recovered for drying from the engine cooling water in case 2. Figure 33 presents the scrubber energy and mass balances. Gas and water enter the scrubber. Cleaned and cooled gas exits the scrubber. The impurities exit with the water. The energy of the gas is recovered mainly from the condensing water, but also from the gas cooling.

The product gas and flue gas scrubber are calculated similarly. The flue gas scrubber is added to the programme (Kurkela, 2016) as a part of this thesis. The energy recovered from the scrubber includes the heat from condensing water vapour and the enthalpy of the gas cooling.

The temperature after the scrubber affects the steam partial pressure, which determines the amount of steam in the flue gas. For ideal gases, the volume fraction ϕ equals the molar fraction and pressure factor for ideal gases, the volume fraction of steam after the scrubber is

$$\phi_{H_2O,2} = \frac{p_{steam}}{p_0} \tag{22}$$

where $\phi_{H_2O,2}$ is the volume fraction of steam [-]
p_{steam} is the steam partial pressure [Pa]
p_0 is the atmospheric pressure [Pa]

Saturated steam pressure regression curves are attained from Tekniikan käsikirja (Jotuni, Ryti and Pöyhönen, 1967). The atmospheric pressure equals 1013 Pa (Perry and Green, 2007, table 2-192).

As the volumetric percentage of steam before the scrubber is known, the amount of condensing water can be obtained.

$$m_{H_2O,condensed} = \frac{V_{H_2O,1} - V_{H_2O,2}}{V_m M_{H_2O}} \tag{23}$$

where $m_{H_2O,condensed}$ is the mass of condensed water [kg]
$V_{H_2O,1}$ volume of steam in the flue gas before the scrubber [m^3]
$V_{H_2O,2}$ volume of steam in the flue gas after the scrubber [m^3]
V_m the molar volume of ideal gas [m^3]
M_{H_2O} the molar mass of water [kg/mol]

The flue gas contains less water after the scrubber. The new volumetric percentage for each component is calculated in equation (24).

$$\phi_{after} = \phi_{before}\frac{100 - \phi_{H_2O,2}}{100 - \phi_{H_2O,1}} \tag{24}$$

where ϕ_{after} is the vol-% of the component in the gas after the scrubber [-]
ϕ_{before} the vol-% of the component in the gas before the scrubber [-]
$\phi_{H_2O,1}$ the vol-% of water in the gas before the scrubber [-]
$\phi_{H_2O,2}$ the vol-% of water in the gas after the scrubber [-]

Equation (25) presents the conversion of the volumetric percentage to mass percentage.

$$w = \phi_{after} \frac{M_i}{\sum M_i} \tag{25}$$

where w is the mass percentage of the component [-]
M_i the molar mass of the component [kg/kmol]

Table 11 lists the molar masses of the flue gas components used in equation (25).

Table 11. The molar masses of the flue gas components. (Perry and Green, 2007, table 2-179)

Component	*Molar mass, kg/kmol*
CO_2	44.010
H_2O	18.015
N_2	28.013
O_2	31.999
SO_2	64.064
CO	28.010
NO	30.006

The specific heat capacity of the flue gas is calculated similarly before and after the scrubber, as seen in equation (26).

$$c_{p-avg} = \sum \frac{m\%_i c_{p-avg,i}}{100} \tag{26}$$

where c_{p-avg} is the averaged specific heat capacity of the gas [kJkg^{-1}°C^{-1}]
$c_{p-avg,i}$ the averaged specific heat capacity of a component [kJkg^{-1}°C^{-1}]

The specific heat capacities of the components, $c_{p-avg,i}$ correlate with temperature, which is taken into account by equations considering the average temperature (Kurkela, 2016).

The enthalpy change of the gas between before (subscript 1) and after the scrubber (subscript 2) equals the heat recovered from the gas in equation (27).

$$\Delta \dot{h} = c_{p-avg,1}\dot{m}_1(T_1 - T_0) - c_{p-avg,2}\dot{m}_2(T_2 - T_0) \tag{27}$$

where $\Delta \dot{h}$ is the enthalpy change of the gas [MW]
$\dot{m}$ is the mass flow of the gas [kg/s]
T is the temperature of the gas [°C]
T_0 is the reference temperature for the enthalpy, 25 °C

Equation (28) takes into account the 0.5 % heat losses.

$$\Phi_{scrubber} = \eta_{scrubber}(\Delta H_{vap}\dot{m}_{H_2O,condensed} + \Delta \dot{h}) \tag{28}$$

where $\eta_{scrubber}$ is the heat recovery efficiency of the scrubber [-]

ΔH_{vap} is the vaporization heat of water at 25 °C, 2.44 MJ/kg

The scrubber efficiency is calculated in equation (29). The scrubber heat losses are the same for all cases, 0.5 % (Kurkela, 2016).

$$\eta_{scrubber} = 1 - 0.005 = 0.995 \quad (29)$$

In cases 1 and 2 the cooled product gas enters the scrubber at 200 °C temperature. Heat is recovered from the enthalpy of the product gas and the condensing water in the scrubber. The temperature after the scrubber equals 30 °C. The gas composition changes in the scrubber and the mass balance is calculated again. NH_3 concentration is 10 ppm-vol at the outlet and other components remain in the gas. (Kurkela, 2016)

In case 2, the total heat available for drying

$$\Phi_{drying,ava} = \Phi_{scrubber} + \Phi_{cooling} \quad (30)$$

where $\Phi_{drying,ava}$ is the available heat for drying [MW]
$\Phi_{cooling}$ is the heat in the engine cooling water [MW]

In case 3, the flue gas enters the scrubber, located after the boiler, at 160 °C temperature. The air preheater and the economizer have collected some of the energy in the flue gas. The temperature of the flue gas after the scrubber is 40 °C. (Kurkela, 2016) The temperatures of the flue gas scrubber are adjusted so that it produces adequately hot water for the drying.

3.3.5 Boiler

The boiler recovers the heat from the product gas and engine flue gases and produces hot water or steam in cases 1 and 2. The hot water provides district heating in case 1 and steam is used for industrial purposes in case 2.

The product gas cools from 700 °C to 200 °C in a hot water boiler before the cleaning in cases 1 and 2. Equation (27) also applies to the product gas cooling. The heat recovered from product gas cooling in the heat recovery boiler is calculated in equation (31). Heat losses constitute 0.5 % of the heat recovered in the boiler.

$$\Phi_{pgb} = \eta_{boiler} \Delta \dot{h} \quad (31)$$

where Φ_{pgb} is the product gas boiler heat output [MW]

The heat from the engine is recovered from the engine cooling water and exhaust gas in a hot water boiler in cases 1 and 2. Flue gas temperature after the boiler equals 90 °C corresponding to the district heating temperatures in case 1. The heat losses of the engine are assumed 3 %. Equation (32) presents the heat output of the flue gas boiler.

$$\Phi_{fgb} = \eta_{boiler} \Phi_{engine} \quad (32)$$

where Φ_{fgb} is the heat output of the flue gas boiler [MW]
η_{boiler} is the boiler efficiency [-]

Thus, equation (33) obtains the district heating output in case 1.

$$\Phi = \Phi_{fgb} + \Phi_{pgb} + \Phi_{scrubber} - \Phi_{drying} \tag{33}$$

where Φ is the district heating output [MW]

For steam generation in case 2, the heat is recovered only from the hot flue gases. The flue gas exits the steam boiler at 180 °C temperature in case 2 due to the 18 bar saturated steam temperature of 206 °C and the feed water warming up in the economizer. The heat from the engine cooling and the remaining heat of the flue gases provide energy for drying purposes. Equation (34) calculates the steam power, Φ.

$$\Phi = \Phi_{pgb} + \Phi_{engine} - \Phi_{cooling} \tag{34}$$

For case 3, the boiler also burns the product gas. Figure 34 illustrates the boiler mass balance in case 3. The product gas and flue gas composition in the figure is presented in volumetric percentage. The air factor of the engine reaches 1.5, but in the boiler the combustion air factor equals 1.2. The chemical composition, LHV and temperature of the product gas going into the combustion remain the same as after the gasifier. (Kurkela, 2016)

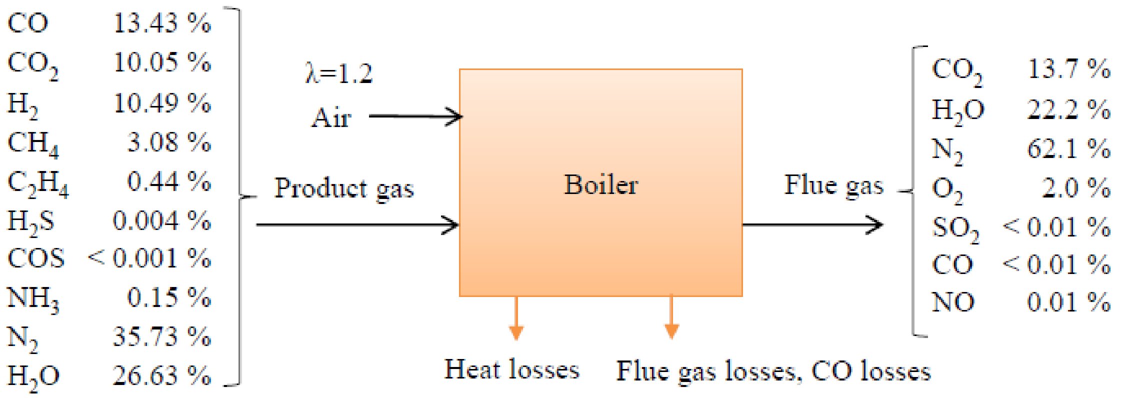


Figure 34. The mass balance of the boiler in Case 3.

For case 3, the boiler and flue gas scrubber replace the gas cooling, gas cleaning, engine and separate heat recovery equipment (Figure 28). The boiler follows the gasification directly without gas cleaning or cooling in between. The gas combustion in the boiler is calculated with the same model as the engine. The programme is edited as a part of this thesis so that the product gas enters the boiler directly. Equation (35) calculates the steam produced in case 3.

$$\Phi = \Phi_{fgb} + \Phi_{scrubber} - \Phi_{drying} \tag{35}$$

The main losses for a boiler are flue gas losses, CO loss and heat losses to the environment by radiation and convection. Boiler radiation losses are assumed 1.5 % and the CO-loss is calculated in the programme with 10 ppm-vol CO in the flue gas (Kurkela, 2016). The flue gas losses are obtained by calculating the enthalpy of the flue gas (equation (36)).

$$\dot{h}_{fg} = c_{p-avg,2}\dot{m}_2(T_2 - T_0) \tag{36}$$

The flue gas losses in case 1 are obtained by calculating the enthalpy of the 90 °C flue gas after the flue gas boiler. In case 2, the flue gas temperature is also 90 °C after the heat recovery for drying. In case 3, the losses are obtained by calculating the enthalpy of the 40 °C flue gas after the scrubber.

3.3.6 Feasibility

The feasibility of the gasifier CHP plant is estimated with payback period, annual profit and NPV. The annual cash flow of the investment can be calculated by summing up the costs and revenues each year. The costs are divided into fixed and variable costs. Variable costs contain feedstock cost and other variable costs, such as operation and maintenance. The fixed costs constitute of the annuity of the investment and other fixed costs, such as labour or fixed operation and maintenance costs. The annuity of the investment cost is calculated as equivalent annual cost. The revenues come from sold energy: electricity, heat and steam.

The initial investment includes feedstock dryer, gasifier and gas cleaning, engine (for the CHP case) and other plant costs, such as feedstock conveyors and ash disposal. The capital costs of gasification CHP with engine in the literature are presented in chapter 2.4.4 (
Table 8 and Figure 26).

The investment costs from the literature are comparable, as they have been converted into 2015 euros. First, the values are converted to year 2015 using chemical engineering plant cost index (CEPCI) (Lozowski, 2009, p. 64; Economic Indicators: Chemical engineering plant cost index (CEPCI), 2016, p. 80). Secondly, the European Central Bank exchange rates convert the sums to euros. Table 12 presents the currency rates (Bank of Finland, 2015).

Table 12. Currency Middle Rates in 2015. (Bank of Finland, 2015)

EUR in currency	*Rate*
USD	1.1095
JPY	134.3140
GBP	0.7258

The cost of a plant in year 2015 is obtained as in equation (37) (Mignard, 2014).

$$I_{2015} = \frac{CEPCI(2015)}{CEPCI(m)} I_m \tag{37}$$

where *I* is the investment costs of the new and reference system [€ or €/kW]
CEPCI (m) is the CEPCI index of the reference year [-]

The scaling of the investment cost data can be done as in equation (38), where subscript 2 corresponds to the new scale and subscript 1 the original scale.

$$I_2 = I_1 \frac{Capacity_2}{Capacity_1}^{y} \tag{38}$$

where *I* is the gasifier investment [€]
Capacityᵢ is the gasifier electrical or heat capacity [MW]

y is the scaling factor [-]

The scaling factor, y, is usually 0.6, which is also used in this thesis. (Danish Energy Agency and Energinet.dk, 2012, p. 14; Jana and De, 2015) As the investment cost of the Kokemäki demonstration plant in 2005 was 4.5 M€ for the 5700 kW_{th} plant. The cost in 2015 is thus 5,351,559 €. This cost is the reference cost for case 1 (Table 13). The specific investment cost equals 2973 €/kW_e. In the literature, the specific investment cost ranged between 1100 and 6000 €/kW_e. Thus, the reference cost is compatible with literature.

Gas engine specific investment cost is 1000…1500 €/kW_e for 1…10 MW natural gas engines. (Danish Energy Agency and Energinet.dk, 2012) A gasification CHP demonstration plant in Piteå, Sweden has a Cummins QSV91 engine. The engine is a lean burn Otto V18 engine of 1200 kW_e with turbo intercooler. The investment cost of the engine is between 679 000…905600 €. (Brandin et al., 2011, p.100) In this case the specific investment cost of an engine is only 565.83…754.67 €/kW_e. According to Salomón *et al.*, the specific investment cost of Otto engines varies between 800 and 1300 €/kW_e (Salomón *et al.*, 2011).

All in all, the chosen specific investment for the engine is 800 €/kW_e. At this cost, the engine reference investment at the Kokemäki plant equals 1.44 M€, which is the reference cost for the engine in cases 1and 2. Thus, the plant cost excluding the engine is 3,911,559 €. This cost is the reference cost for the plant without the engine. The specific investment cost for the 5700 kW_{th} plant without the engine is 686 €/kW_{th}. In the literature, the specific investment of updraft gasifiers for heat-only production 570…1100 €/kW_{th}. (Dornburg and Faaij, 2001) A gas fired district heating boiler costs 70…130 €/kW_{th}. (Danish Energy Agency and Energinet.dk, 2012) Thus, the reference cost matches the investment costs in literature.

Table 13. Investment costs of the cases.

Case	*Investment (€)*	*Engine (€)*	*Specific cost*
1c Kiteen Lämpö 160 kW_e	836,568		5572 €/kW_e
1b 1 MW_{DH}	2,482,036	732,901	4250 €/kW_e
1a Savon Voima 5 MW_{DH}	6,762,817	2,116,302	1978 €/kW_e
1a Savon Voima 10 MW_{DH}	10,414,169	3,332,860	1427 €/kW_e
2 Raute 8 MW_{steam}	11,851,881	3,478,968	1514 €/kW_e
3 Turku Energia 750 kW_{steam}	1,158,409		791 €/kW_{th}

Table 13 compares the investment costs of the cases. The investment costs of case 2 increase due to two gasifier lines. In case 1c, an existing engine utilizes the product gas, which decreases the investment costs.

The revenues depend on electricity, heat and steam production. The electricity, district heating or steam production efficiency of the plant is obtained from the mass- and energy balances. The full load hours correspond to the heat or steam demand.

As the prices of electricity, heat and steam are known, the annual revenues from the production can be calculated separately for each product. Thus, the yearly revenue is calculated as in equation (39).

$$AR = P_{el}he + \Phi hs \tag{39}$$

where AR is the annual revenue [€]
P_{el} is the electric power [MW]
Φ the district heating or steam output [MW]
h full load hours [h]
e electricity price [€/MWh]
s steam or heat price [€/MWh].

The annual feedstock cost is calculated similarly in equation (40).

$$feedstock\ cost = \Phi_{fuel} hf \tag{40}$$

where Φ_{fuel} is the fuel power [MW]
f marks the feedstock price [€/MWh]

Additionally, the landfill gas cost is calculated in case 1c.

$$landfill\ gas\ cost = \Phi_{LFG} hf_{LFG} \tag{41}$$

where f_{LFG} is the landfill gas price [€/MWh]

The fixed operation and maintenance costs are assumed to be 3 % of the investment and the variable costs without feedstock cost are 18 €/MWh. This is the typical figure found in literature in chapter 2.4.4 for gasifier CHP with engine. In case 3 - without engine or gas cleaning - the variable operation and maintenance costs decrease. According to the Danish Energy Agency report, the total operation and maintenance costs of a 1…10 MW gas engine add to 7.40…11 €/MWh. Thus, the operation and maintenance costs are assumed 9 €/MWh, which is 9 €/MWh less than in cases 1 and 2. The annual variable non-feedstock cost is calculated as in equation (42) and the annual fixed operation and maintenance cost is obtained from equation (43).

$$annual\ variable\ OM\ cost = P_{el} hO_v \tag{42}$$

$$annual\ fixed\ OM\ cost = O_v I_0 = 0.03 I_0 \tag{43}$$

where h marks the full load hours [h]
O_v the variable costs [€/kW$_e$]
I_0 is the initial investment [€]
O_f the fixed operation and maintenance costs [-]

Thus, the annuals costs

$$AC = \Phi_{fuel} hf + \Phi_{LFG} hf_{LFG} + P_{el} hO_v + O_f I_0 \tag{44}$$

The equivalent annual cost (EAC) of the investment can be calculated as in (45), if the residual value is assumed zero. The EAC divides the investment cost evenly across the lifetime of the investment.

$$EAC = I_0 c \tag{45}$$

where c is the capital recovery factor [-]

The capital recovery factor

$$c = \frac{(1+i)^n i}{(1+i)^n - 1} = \frac{(1+0.1)^{20} 0.1}{(1+0.1)^{20} - 1} = 0.1175 \tag{46}$$

where n is the lifetime of the investment [a]
i interest rate [-]

The interest rate only takes into account the return on equity and inflation. No external capital is included in the calculations.

Table 14 presents the initial values of the feasibility calculations.

Table 14. Initial values for the feasibility of the case studies.

Case	*1a*	*1b*	*1c*	*2*	*3*
Heat/steam (MW)	5;10	1	290	8	0.75
Power (kW)	3400;7300	580	160	7800	
Fuel power (MW)	9.5; 19.5	1.8	0.5	20.8	0.87
Full load hours (h)	8000	7000	8322	7680	7000
Electricity price (€/MWh)	30	30	40	75	
Heat price (€/MWh)	30.95;29.90	64	54	60	70
Feedstock costs (€/MWh)	16	22	21	20	20
Landfill gas cost (€/MWh)			30		
Variable O&M (€/MWh)	18	18	18	18	9
Fixed costs (%)	3	3	3	3	3
Interest rate (%)	8	5	10	6	5
Investment lifetime (years)	20	20	20	20	25
Process electrical efficiency (%)	36.0;37.4	32.6	31.5	37.5	
Heat/steam efficiency (%)	52.6;51.3	55.9	58.0	38.4	85.8
Total efficiency (%)	88.6;88.7	88.5	89.4	75.9	85.8

The annual profit takes into account the equivalent annual costs of the investment.

$$AP = AR - AC - EAC \tag{47}$$

where AP the annual profit [€]
AR the annual revenue [€]
AC the annual operation, maintenance and feedstock costs [€]
I_0 the initial investment [€]

The simple payback period (PBP) of the investment in equation (48) ignores discounting.

$$PBP = \frac{I_0}{AR - AC} \tag{48}$$

The discounted payback period is calculated by finding the number of years, *n,* with which the net present value in equation (49) equals zero or by finding the year where cumulative discounted cash flow becomes positive.

Net present value (NPV), when the investment cost is paid in the beginning and the annual cash flow ($AR - AC$) is constant

$$NPV = \frac{1}{c}(AR - AC) - I_0 \tag{49}$$

Internal rate of return (IRR) is the interest rate with which the NPV equals zero. Electricity, heat or steam break-even price is obtained by finding the price at which the NPV equals zero.

The levelized cost of energy (LCOE) for heat or steam (50).

$$LCOE = O_v + f + \frac{O_f}{\Phi h} + \frac{EAC}{\Phi h} \tag{50}$$

3.3.7 Sensitivity analysis calculations

The sensitivity analysis varies the prices to determine the change in profitability. Table 15 shows the sensitivity analysis ranges. The 'Case' column tells in which cases the sensitivity is examined for each price. Additionally, the effect of plant size is studied by four different plant sizes in each case. The plant sizes in case 1 depend on the cases. The additional capacities in cases 2 and 3 are 1, 2 and 4 MW_{steam}.

Table 15. Price ranges for the sensitivity analysis.

Variable	*Range, €/MWh*	*Case*
Electricity price	25…400	1, 2
Heat price	30...70	1
Steam price	50...90	2, 3
Feedstock price	5...25	1, 2, 3

The sensitivity analysis studies the NPV, simple payback period and annual profit in more detail. The formulas for these three are modified so that they contain all the prices. Thus, changing the prices in equations (51) to (56), the sensitivity of the feasibility indicators can be tabulated.

For cases 1 and 2 the net present value

$$NPV = \frac{1}{c}\left[P_{el}he + \Phi hs - \left(\Phi_{fuel}fh + \Phi_{LFG}hf_{LFG} + P_{el}hO_v + O_f I_0\right)\right] - I_0 \tag{51}$$

The simple payback period

$$PBP = \frac{I_0 P_{el}}{P_{el}he + \Phi hs - \left(\Phi_{fuel}hf + \Phi_{LFG}hf_{LFG} + P_{el}hO_v + O_f I_0\right)} \tag{52}$$

The annual profit

$$AP = P_{el}he + \Phi hs - \left(\Phi_{fuel}hf + \Phi_{LFG}hf_{LFG} + P_{el}O_v h + O_f I_0\right) - cI_0 \tag{53}$$

For case 3 the net present value

$$NPV = \frac{1}{c}\left[\Phi hs - \left(\Phi fh + P_{el} hO_v + O_f I_0\right)\right] - I_0 \tag{54}$$

The simple payback period

$$PBP = \frac{I_0 P_{el}}{\Phi hs - \left(\Phi_{fuel} hf + P_{el} hO_v + O_f I_0\right)} \tag{55}$$

The annual profit

$$AP = \Phi hs - \left(\Phi_{fuel} hf + P_{el} O_v h + O_f I_0\right) - cI_0 \tag{56}$$

4 Results and discussion

4.1 Case 1: District heating CHP

District heating CHP production in Finland is not profitable with gasification and engine configuration, as was expected considering the low electricity prices. The higher investment costs of CHP favor heat-only production (Salomón *et al.*, 2011). Table 16 presents the results of case 1. The investments do not show a profit with the initial values presented in Table 9, as the net present value remains negative.

Table 16. Results of case 1.

Case	*1c, 0.3 MW_{DH}*	*1b, 1MW_{DH}*	*1a, 5 MW_{DH}*	*1a, 10 MW_{DH}*
Annuity of capital (€)	89,334	199,165	688,808	1,060,706
Annual profit (€)	-68,631	-52,135	-428,671	-467,732
Annual cash flow (€)	20,703	147,030	260,137	592,974
Net Present Value (€)	-584,291	-649,720	-4,208,756	-4,592,260
Simple PBP (a)	36.7	16.9	26.0	17.6
Discounted PBP (a)	40.4	17.7	27.1	19.0
IRR	-5.2 %	1.7 %	-2.4 %	1.3 %
BEP Power (€/MWh)	100.41	42.75	45.67	38.02
BEP Heat (€/MWh)	108.41	71.45	44.49	39.62

Case 1a (Savon Voima) compares the CHP production to heat-only district heating plant, as the heat price is the levelized cost of heat in a district heating boiler with the same feedstock, which was calculated in chapter 3.2.3. Case 1b studies a smaller CHP plant with lower interest rate, which corresponds to the situation of small heat companies in Finland. Case 1c combines gasification with landfill gas production. Due to the small size of the engine, only 160 kW_e, and the high investment costs, the investment only becomes profitable at high electricity prices, above the electricity break-even price of 100 €/MWh.

The annual cash flow achieves positive results. However, the annual profit remains negative due to the EAC included in the annual profit. Annual profit and NPV behave similarly, as the prices change. The simple payback period shortens with higher electricity and heat prices and lower feedstock costs.

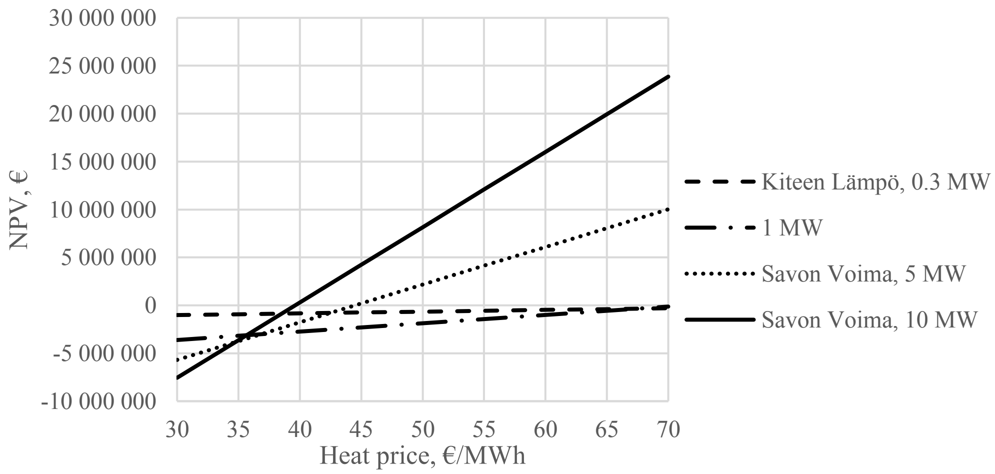


Figure 35. NPV sensitivity to heat price.

Sensitivity to heat price (Figure 35) reveals that higher heat price does not turn cases 1b and 1c profitable even at 70 €/MWh heat prices. The NPV turns positive in case 1a by increasing heat price from 30 to 50 €/MWh.

Figure 36 illustrates the NPV sensitivity to feedstock price. Case 1b (1 MW district heat) becomes profitable while feedstock price decreases under 15 €/MWh. In case 1a, both options show positive NPV below 8 €/MWh feedstock prices. NPV remains negative despite the lower feedstock prices in option 1c (Kiteen Lämpö).

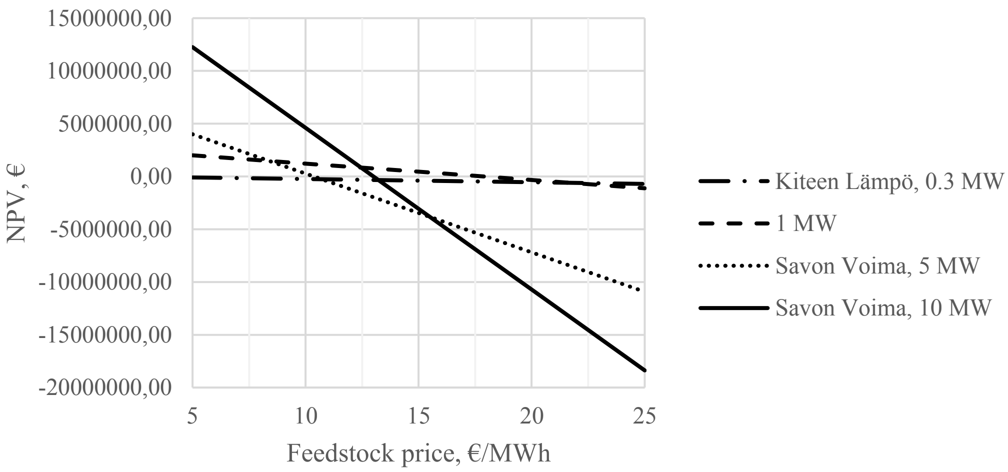


Figure 36. NPV sensitivity to feedstock price.

Figure 37 presents the NPV as a function of the electricity price. High electricity price affects the profitability positively. Countries with high electricity price for households include Germany, Denmark, Italy, Portugal and the UK (OECD/IEA, 2015). The electricity prices for industry start from 50 €/MWh (OECD/IEA, 2015), which exceeds the electricity break-even price for cases 1a and 1b. Thus, replacing electricity purchase with own production would be profitable, although selling the electricity at market price is not profitable. On the other hand, countries with low electricity prices offering biomass electricity feed-in-tariff are attractive for this kind of investments. The feed-in tariff of 103.50 €/MWh for small-scale CHP installations added with a heat bonus of 20 €/MWh for plants utilizing wood in Finland (Energy Authority, 2016) would make the investment profitable for the 12 year period.

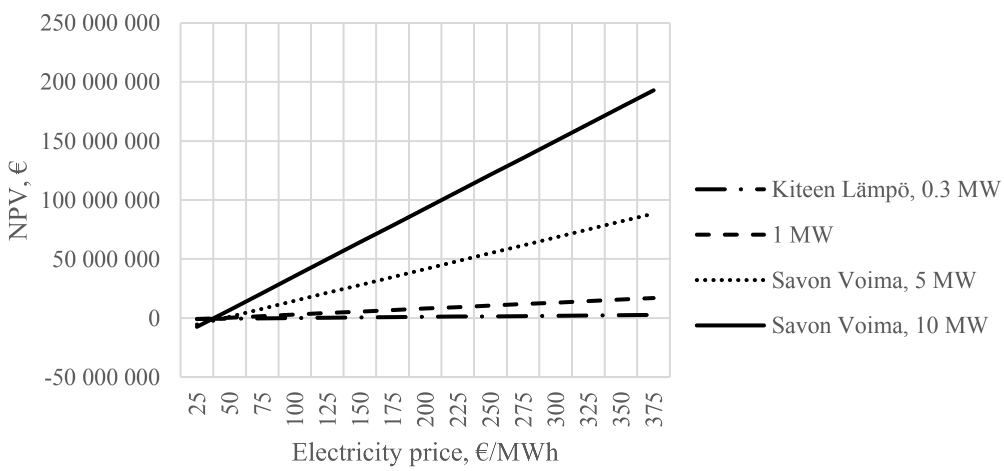


Figure 37. NPV sensitivity to electricity price.

In Japan, the 238…297 €/MWh feed-in tariffs for 20 years (OECD/IEA, 2016) would be more than sufficient for the profitability of the investment. The investment would also be profitable in Austria, where the feed-in-tariff of 149.80 €/MWh is paid for 15 years with an additional 20 €/MWh for efficient cogeneration.

Additionally, investment cost and interest rate affect the results. The investment subsidy available in Finland, 30 % of the investment cost fails to transform the investments profitable with low electricity prices. The higher interest rate of case 1c increases the difficulty of profitability. Case 1b seems advantageous due to the lower interest rate.

Earlier studies have investigated the feasibility of biomass gasification CHP. The effect of plant size (Skorek-Osikowska *et al.*, 2014) as well as feedstock costs and electricity price (Yagi and Nakata, 2011) has been studied.

The results of this thesis compare to those of the 250 kW_e district heating plant by Dell'Antonia e*t al*. In their calculations, a CHP plant with 4040 €/kW_e investment cost and 4 % interest rate has a PBP of 5 years and NPV of 1.9 M€. These results are obtained with 229 €/MWh base price for electricity and a 40 €/MWh heat grant. (Dell'Antonia *et al.*, 2014)

Also Skorek-Osikowska et al. study the effect of plant size in the profitability of biomass gasification CHP with ICE in Poland. They find that the technology becomes easily unprofitable without green certificates or other subsidies. Their system becomes profitable at 440 kW_e size, with approximately 5 % interest rate and 117 €/MWh electricity price including green certificates. They also state, that the electricity and feedstock prices are integral for the economy of the biomass gasification CHP. Additionally, heat price and interest rate influence the profitability, as they do in this thesis. (Skorek-Osikowska *et al.*, 2014)

Yagi and Nakata investigate the profitability of biomass gasification in Japan with different biomass feedstocks. They study especially the sensitivity to feedstock price and availability compared to electricity price. Sawmill waste becomes feasible for 27…153 €/MWh electricity prices, logging residues for above 153 €/MWh and thinned wood above 207 €/MWh. (Yagi and Nakata, 2011)

4.2 Case 2: Industrial CHP

The industrial CHP plant of Raute is profitable at the initial prices, electricity 75 €/MWh and steam 60 €/MWh. Table 17 provides the data from the calculations. All of the annual profits and net present values are positive and the discounted payback period of the 8 MW plant is only 3.8 years. Additionally, the IRR of the investment is 29.8 %. This case is the most promising option for Gasgen demonstration without feed-in-tariffs or other subsidies. The investment is profitable also with lower steam and electricity prices, as the break-even prices are low (Table 6).

The small 1 MW steam industrial CHP plant also remains feasible, although the annual profits are low. The payback periods stay short in the sensitivity analysis. Profitability increases with size due to the scaling factor in equation (38). The high initial steam and electricity prices benefit the profitability. Additionally, the relatively low (6 %) interest rate also enhances the positive results.

Table 17. Results of case 2.

Size, MW steam	*1 MW*	*2 MW*	*4 MW*	*Raute 8 MW*
Annuity of capital (€)	273,902	425,397	663,231	1,033,301
Annual profit (€)	75,493	341,671	998,919	2,521,847
Annual cash flow (€)	349,395	767,068	1,662,151	3,555,148
Net Present Value (€)	865,901	3,918,941	11,457,523	28,925,387
Simple PBP (a)	9.0	6.4	4.6	3.3
Discounted PBP (a)	13.3	8.2	5.5	3.8
IRR	9.2 %	14.7 %	21.4 %	29.8 %
BEP Power (€/MWh)	62.55	48.65	39.29	33.06
BEP Steam (€/MWh)	50.17	37.76	27.48	18.95

Figure 38 shows the sensitivity of the NPV with changing prices. Decreasing the feedstock price makes the investment more profitable. Many industrial customers possess inexpensive by-products suitable for feedstock of the Gasgen gasifier valued under the high initial value of 20 €/MWh. Although the different feedstock composition slightly affects the gasifier efficiency, these would provide a very profitable option for the demonstration. Additionally, the investment would be profitable at much lower steam and electricity prices than the initial values in Table 14.

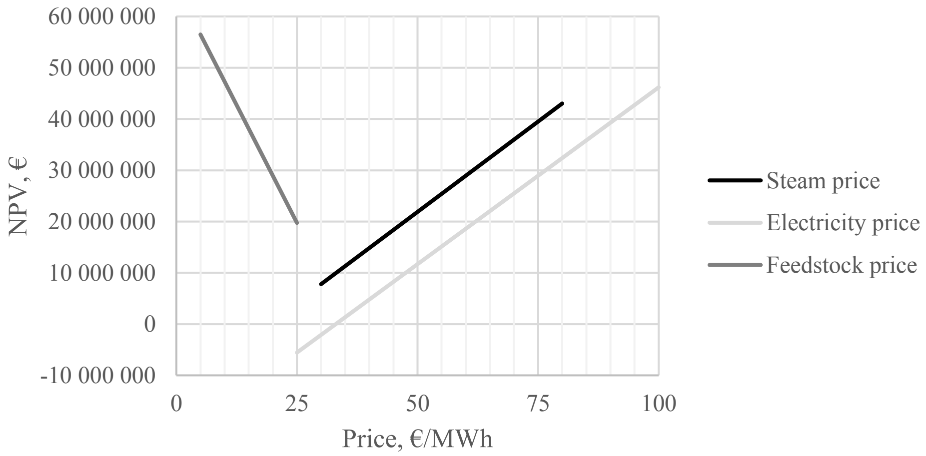


Figure 38. NPV sensitivity price changes.

The results of earlier studies resemble these results. A small 1 MW_e plant (Celma, Blázquez and López-Rodríguez, 2013) has higher NPV and high IRR. On the other hand, the 1421 kW_e DFB coupled with gas engine is not feasible with 10 % interest rate. Larger LVL and MDF mills are more profitable. (Penniall and Williamson, 2009)

Celma et al. evaluate an industrial biomass gasification CHP more feasible than a natural gas CHP in Spanish olive processing industry. The former olive pit boiler produced steam. Thus, the primary energy demand decreased by introducing CHP, which enabled annual savings on both natural gas and biomass gasification. The NPV of the gasification CHP equals 1.38 M€, assuming 144.90 €/MWh electricity price, which includes cogeneration complements. The IRR of the investment equals 24.8 %. (Celma, Blázquez and López-Rodríguez, 2013)

Similarly, Penniall and Williamson studied the feasibility of a dual fluidized bed gasifier at wood processing industry in New Zealand. Their feasibility study yields a simple payback time of 9.5 years at a sawmill, 7.5 years at an LVL mill and 6 years at a medium density fiberboard mill. (Penniall and Williamson, 2009)

4.3 Case 3: Steam generation replacing fuel oil

Steam production with gasification is profitable at the 70 €/MWh initial steam price, 25 years investment lifetime and 5 % interest rate. Table 18 presents the economic indicators of four different sized plants in case 3. All the plants have positive annual profits and net present values. Additionally, the payback periods remain under 10 years. The profitability increases along with plant size. Economics of scale affect the investment cost, as the larger plants are more profitable due to the lower specific investment cost. Larger capacity benefits the feasibility due to the scaling factor, *y*, which decreases the specific investment costs of the larger plants. However, also the small steam plants are profitable.

Table 18. Results of case 3, 750 kW represents the Turku Energia case.

Size	***750 kW***	*1 MW*	*2 MW*	*4 MW*
Annuity of capital (€)	82,192	110,466	148,051	224,403
Annual profit (€)	73,050	101,559	296,001	694,016
Annual cash flow (€)	155,242	212,025	444,052	918,418
Net Present Value (€)	1,029,557	1,265,651	4,171,819	9,781,418
LCOE steam (€/MWh)	51.28	50.68	44.05	40.40
Simple PBP (a)	7.5	6.5	4.7	3.4
Discounted PBP (a)	9.6	8.0	5.5	3.9
IRR	12.7 %	14.4 %	21.1 %	29.0 %
BEP Steam (€/MWh)	56.09	55.49	48.86	45.21

Figure 39 shows the net present value of the investment as a function of steam price. The plants become profitable above the steam break-even price and the profitability increases simultaneously with steam price. Annual profit and NPV behave similarly, as the prices change. The simple payback period shortens with higher electricity and heat prices and lower feedstock costs.

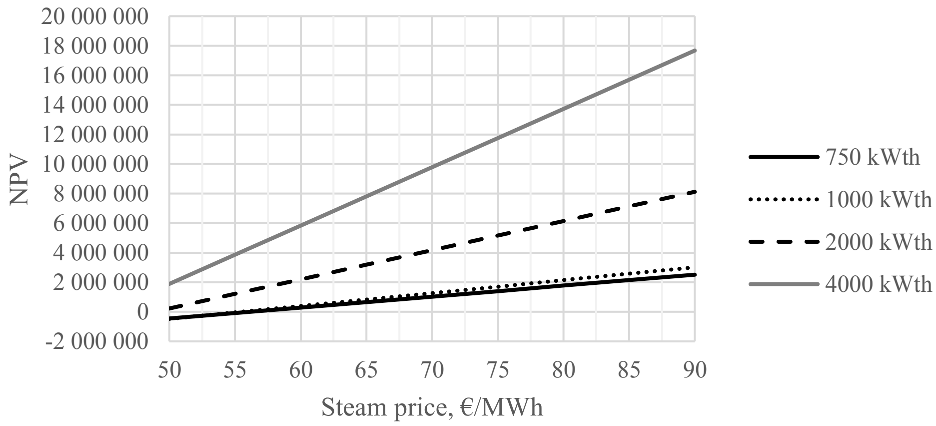


Figure 39. NPV sensitivity to steam price.

If feedstock price decreases, the investment becomes more profitable (Figure 40). Even the 750 kW steam plant. The increase in net present value compared to the effect of steam price. Lowering the feedstock price means changing the feedstock, which would also affect the energy balance. This effect is not considered in the sensitivity analysis.

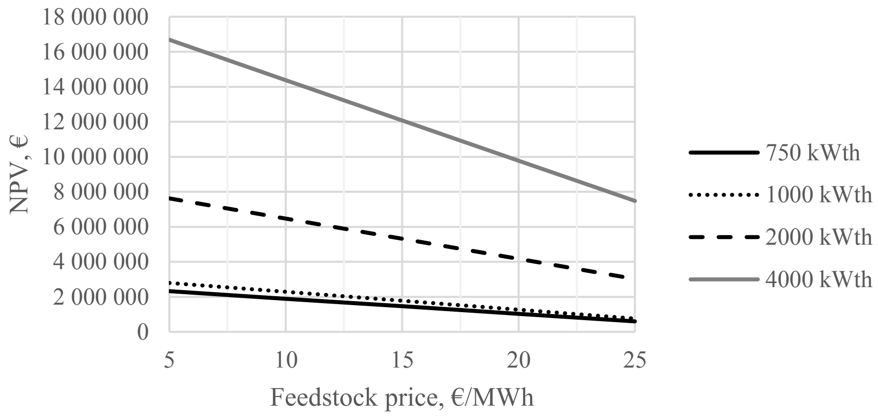


Figure 40. NPV sensitivity to feedstock price.

The levelized cost of steam produced equals 51.28 €/MWh, when the capital costs are allocated evenly across the 25-year investment lifetime. Thus, the gasification boiler combination generates savings if the alternative fuel price exceeds the LCOE. In June 2016 the heavy fuel oil price in Finland was 44.60 €/MWh, light fuel oil price 65.60 €/MWh and natural gas 39.30 €/MWh (Pöyry, 2016). All in all, at present heavy fuel oil and gas prices, the investment in new biomass gasification steam plant is only feasible if the existing fuel oil plant is at the end of its lifetime. Light fuel oil price applies for small consumers such as farmers and not for large consumers like a steam plant. However, at the 65 €/MWh small consumer light fuel oil price, the investment would be profitable.

4.4 Validity and reliability

The feasibility study disregards the technological risks related to the new gasifier and its scale-up. Detailed cost assessment is recommended after demonstration in industrial steam CHP production. Additionally, operation and maintenance cost should be assessed at the demonstration plant. Then cases 1 and 3 could be reassessed.

The initial values of the case calculations arise from the Finnish context. The sensitivity analysis allows the generalization of the results to other countries and different market conditions. The results can be generalized to small-scale biomass gasification plants (Table 19). The sizes correspond to the fuel power of the plant.

Table 19. Applicable size range of the feasibility study.

	Applicable size range
Case 1	0.5…20 MW_{th}
Case 2	2…22 MW_{th}
Case 3	0.7…5 MW_{th}

The results of cases 1 and 2 are reliable in the small-scale gasification-gas-engine CHP application both district heating and small industry applications. The results of case 3 are less reliable due to the possible errors in the investment cost calculation. The sources of error arise from the energy balances and the economic calculations. The main sources of error are discussed below.

The energy balance calculations conducted as a part of this thesis concentrated on case 3. The inlet and outlet temperatures of the flue gas scrubber were obtained by finding the optimal temperatures regarding the dryer energy consumption. Additionally, the boiler Rankine cycle modeled only by the outlet temperature, which includes the preheating of air and feed water. The feedstock-to-steam efficiency of the process equals 86 %, which is a typical value. Thus, the energy balance calculations present no major errors to the feasibility calculations.

Minor sources of error in the energy and mass balances include loss percentages and engine efficiency. The engine efficiencies have been calculated according to biogas efficiencies using one reference point, which increases the error margin of the electricity production. Loss percentages are based on experience from gasification research (Kurkela, 2016).

Sources of error in the economic calculations include operation and maintenance costs, full load hours and investment cost. Operation and maintenance costs are based on the literature study, thus depicting the Gasgen technology imprecisely. No specific values are available for the new technology and the operation and maintenance costs are more likely to be too high than too low. The results of this thesis neglect the variation in the heat demand, which affects the full load hours.

The investment cost of case 3 was obtained by subtracting the engine investment cost from the reference investment. The engine cost obtained from the literature excludes the generator and other electricity-related equipment. Thus, the investment cost might be considerably too high due to extra costs remaining in the investment costs. On the other hand, modifications are required while changing boiler fuel from fuel oil to product gas. The cost of the gas cleaning equipment included in the investment could be allocated to the modifications.

Moreover, the economic calculations exclude income taxes and value added tax. The interest rate takes into account only the return on equity and inflation. No external capital is included in the calculations.

5 Summary/Conclusion

This thesis aimed to evaluate the market potential and competitiveness of the Gasgen gasifier coupled with internal combustion engine to produce small-scale CHP in a concrete operating environment. The gasifier is compared to other small-scale gasifiers and the ICE is compared to other small-scale power production technologies in the literature study. Moreover, market perspectives and the special features of biomass feedstock are discussed.

Fixed bed gasifiers dominate the small-scale gasification markets due to reliable and simple technology. Even conventional downdraft gasifiers produce low-tar product gas. Updraft gasifiers customarily produce gas for heating applications due to the high tar content. Fluidised bed technology complicates the gasifier operation and increases the costs compared to fixed bed gasifiers.

Gasgen technology integrates in-situ tar decomposition with fixed bed gasifier. The feedstock enters at the upper part of the gasifier and passes the pyrolysis zone. The final gasification occurs in the lower part of the gasifier. Primary air is fed countercurrently from the bottom of the gasifier. The product gas passes a catalyst layer and the tars are reformed. The reforming air is fed at the sides of the gasifier. (FI 126357, 2016) The scalability and wide feedstock selection differentiate the Gasgen technology from the other downdraft designs.

The main advantages of the ICE are the electrical efficiency in small-scale, also on part-load operation, and mature technology with reasonable costs. Gas turbines top ICEs on full load. The higher efficiency of fuel cells increases also the investment costs. Rankine cycles and steam engines present much lower efficiencies and Stirling engines are limited to maximum 100 kW_e size.

Various biomass feedstocks for Gasgen gasification are available around the world. Local wood species and forest industry by-products constitute the main feedstocks in Europe, America, Africa and Asia. Agricultural residues hold high ash contents. However, high-lignin agricultural biomass emerges as a potential small-scale gasification feedstock in Southeast Asia (Mendu *et al.*, 2012).

The challenges related to biomass feedstock include transport, high moisture content and gas impurities damaging the engine. The low energy density of biomass makes the transportation costly. (Bocci *et al.*, 2014) Pelletizing or briquetting can resolve the issues with low density. The suitable drying technologies identified for biomass in small-scale gasification application are rotary, band conveyor and perforated floor dryers (Brammer and Bridgwater, 1999). Product gas cleaning and engine cooling provide the heat required by the drying.

The main countries producing electricity from biomass are the United States, Brazil, Germany, Japan, UK, Finland, Sweden, Italy, Poland and the Netherlands. In Northern Africa no electricity is produced from biomass. Also Sub-Saharan Africa, Middle-East, Australia, Central America and Western Asia are characterized by minor shares of bioelectricity. (Observ'ER and Fondation Énergies pourle Monde, 2013)

Market perspectives look bright in the light of policies and subsidies for biomass energy especially in Japan and Austria. EU and national targets for renewable energy result in biomass energy promotion also in Finland, Germany and the UK. Existing small-scale biomass gasification CHP plants are located mainly in Europe and China. Additionally, demonstration plants have been built in Japan.

The feasibility study is conducted by modifying the mass and energy balance program (Kurkela, 2016). The feasibility is evaluated by calculating annual profit, PBP and NPV. Additionally, IRR, LCOE and break-even prices are examined to analyse the results. Sensitivity analysis is conducted by varying electricity, heat or steam and feedstock prices.

The district heating CHP application (Case 1) is only feasible with higher electricity prices than in Finland, electricity production for own use or feed-in-tariffs. The smaller plants require higher electricity prices for profitability. The break-even electricity prices of the 1…10 MW_{DH} plants are approximately 40…50 €/MWh. However, the small 160 kW_e engine CHP plant utilizing also landfill gas breaks even at 100 €/MWh electricity price due to economics of scale and high interest rate.

The 8 MW industrial CHP (Case 2) is profitable even with relatively low electricity and steam prices, compared to electricity prices for industry (OECD/IEA, 2015). This case is the most promising option for Gasgen demonstration without feed-in-tariffs. Many industrial customers possess inexpensive by-products suitable for Gasgen feedstock valued under the initial value of 20 €/MWh. Decreasing the feedstock price makes the investment more profitable. Smaller scale plants are also feasible, although the NPV decreases. Smaller plants are less profitable due to the economics of scale and the electrical efficiency equation of the engine.

Steam generation by gasification (Case 3) replaces fuel oil productively in 750 kW scale if the oil prices are above the levelized cost of energy, 51 €/MWh. At present oil and gas prices, the investment in new biomass gasification steam plant is only feasible if the existing fuel oil plant is at the end of its lifetime. Larger scale improves the profitability also in case 3.

The initial values of the cases arise from the Finnish context. The sensitivity analysis allows the generalization of the results to other countries and different market conditions. The district heating CHP application is profitable with the subsidies available in Japan and Austria.

The feasibility study disregards the technological risks related to the new gasifier and its scale-up. Detailed investment cost assessment is recommended after demonstration in industrial steam CHP production. Additionally, operation and maintenance cost should be assessed at the demonstration plant. Then cases 1 and 3 could be reassessed.

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Appendices

Appendix 1. Initial values of the mass- and energy balance calculations. 1 page.

Appendix 1. Initial values of the mass- and energy balance calculations.

Case *MW_{DH} / MW_{steam}*	*1c* *0.3*	*1b* *1*	*1a* *5;10*	*2* *8*	*3* *0.75*
Feedstock moisture content before dryer, %	50	50	50	50	50
Feedstock moisture content after dryer, %	15	15	15	15	30
Dryer efficiency, %	60	60	60	60	60
Gasifier heat losses, %	1.7	1.7	1.7	1.7	1.4
Scrubber losses, %	0.5	0.5	0.5	0.5	0.5
Engine electrical efficiency, %	34.97	36.78	40.25; 41.68	26.81	
Engine/boiler heat losses, %	3	3	3	3	1.5
NH3 concentration after scrubber, ppm-v	10	10	10	10	
Engine/boiler air factor	1.5	1.5	1.5	1.5	1.2
CO in the flue gas, vol-ppm	500	500	500	500	10
NO in the flue gas, vol-ppm	100	100	100	100	100
Preheated air to the gasifier, °C	250	250	250	250	210
Reference temperature	25	25	25	25	25
Gas temperature after air preheater, °C	700	700	700	700	720
Gas temperature after heat recovery boiler, °C	200	200	200	200	
Gas temperature after scrubber, °C	30	30	30	30	40
Flue gas temperature after DH/steam prod., °C	90	90	90	90	160